THE GRID CODE

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*does not constitute part of the Grid Code
PREFACE

(P)

(This section does not form part of the Grid Code)

P.1. The Grid Code sets out the operating procedures and principles governing the relationship between The Company and all Users of the National Electricity Transmission System, be they Generators, DC Converter owners, Suppliers or Non-Embedded Customers. The Grid Code specifies day-to-day procedures for both planning and operational purposes and covers both normal and exceptional circumstances.

P.2 The Grid Code is designed to:

(i) permit the development, maintenance and operation of an efficient, coordinated and economical system for the transmission of electricity;

(ii) facilitate competition in the generation and supply of electricity (and without limiting the foregoing, to facilitate the national electricity transmission system being made available to persons authorised to supply or generate electricity on terms which neither prevent nor restrict competition in the supply or generation of electricity);

(iii) promote the security and efficiency of the electricity generation, transmission and distribution systems in the national electricity transmission system operator area taken as a whole; and

(iv) efficiently discharge the obligations imposed upon the licensee by this license and to comply with the Electricity Regulation and any relevant Legally Binding Decisions of the European Commission and/or the Agency.

and is conceived as a statement of what is optimal (particularly from a technical point of view) for all Users and The Company itself in relation to the planning, operation and use of the National Electricity Transmission System. It seeks to avoid any undue discrimination between Users and categories of Users.

P.3 The Grid Code is divided into the following sections:

(a) a Planning Code which provides generally for the supply of certain information by Users in order for The Company to undertake the planning and development of the National Electricity Transmission System;

(b) the Connection Conditions which specify minimum technical, design and operational criteria which must be complied with by The Company at Connection Sites and by Users connected to or seeking connection with the National Electricity Transmission System or by Generators (other than in respect of Small Power Stations) or DC Converter owners, connected to or seeking connection to a User’s System;

(c) the Compliance Processes which specify the process that must be followed by The Company and any Generator or DC Converter Station owner to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus.
(d) an Operating Code, which is split into a number of sections and deals with Demand forecasting (OC1); the co-ordination of the outage planning process in respect of Large Power Stations, the National Electricity Transmission System and User Systems for construction, repair and maintenance, and the provision of certain types of Operating Margin data (OC2); testing and monitoring of Users (OC5); different forms of reducing Demand (OC6); the reporting of scheduled and planned actions, and unexpected occurrences such as faults (OC7); the co-ordination, establishment and maintenance of Isolation and Earthing in order that work and/or testing can be carried out safely (OC8); certain aspects of contingency planning (OC9); the provision of written reports on occurrences such as faults in certain circumstances (OC10); the procedures for numbering and nomenclature of HV Apparatus at certain sites (OC11); and the procedures for the establishment of System Tests (OC12);

(e) a Balancing Code, which is split into three sections and deals with the submission of BM Unit Data from BM Participants, and of certain other information, for the following day and ahead of Gate Closure (BC1); the post Gate Closure process (BC2); and the procedures and requirements in relation to System Frequency control (BC3);

(f) a Data Registration Code, which sets out a unified listing of all data required by The Company from Users, and by Users from The Company, under the Grid Code;

(g) General Conditions, which are intended to ensure, so far as possible, that the various sections of the Grid Code work together and work in practice and include provisions relating to the establishment of a Grid Code Review Panel and other provisions of a general nature.

This Preface is provided to Users and to prospective Users for information only and 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 Control Based Droop Power** | The Active Control Based Power output supplied by a Grid Forming Plant through controlled means (be it manual or automatic).  
For GBGF-I this is equivalent to a Synchronous Generating Unit with a traditional governor coupled to its prime mover.  
Active Control Based Droop Power is used by The Company to control System Frequency changes through the instruction of Primary Response and Secondary Response. |
### Active Control Based Power

The **Active Power** output supplied by a **Grid Forming Plant** through controlled means (be it manual or automatic) of the positive phase sequence Root Mean Square **Active Power** produced at fundamental **System Frequency** by the control system of a **Grid Forming Unit**.

For GBGF-I, this is equivalent to a **Synchronous Generating Unit** with a traditional governor coupled to its prime mover.

**Active Control Based Power** includes **Active Power** changes that result from a change to the **Grid Forming Plant Owners** available set points that have a 5 Hz limit on the bandwidth of the provided response.

**Active Control Based Power** also includes **Active Power** components produced by the normal operation of a **Grid Forming Plant** that comply with the **Engineering Recommendation** P28 limits. These **Active Power** components do not have a 5 Hz limit on the bandwidth of the provided response.

**Active Control Based Power** does not include **Active Power** components proportional to **System Frequency**, slip or deviation that provide damping power to emulate the natural damping function provided by a real **Synchronous Generating Unit**.

### Active Damping Power

The **Active Power** naturally injected or absorbed by a **Grid Forming Plant** to reduce **Active Power** oscillations in the **Total System**.

More specifically, **Active Damping Power** is the damped response of a **Grid Forming Plant** to an oscillation between the voltage at the **Grid Entry Point** or **User System Entry Point** and the voltage of the **Internal Voltage Source** of the **Grid Forming Plant**.

For the avoidance of doubt, **Active Damping Power** is an inherent capability of a **Grid Forming Plant** that starts to respond naturally, within less than 5ms to low frequency oscillations in the **System Frequency**.

### 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 Frequency Response Power

The injection or absorption of **Active Power** by a Grid Forming Plant to or from the **Total System** during a deviation of the **System Frequency** away from the **Target Frequency**.

For a GBGF-I this is very similar to **Primary Response** but with a response time to achieve the declared service capability (which could be the **Maximum Capacity** or **Registered Capacity**) within 1 second.

For GBGF-I this can rapidly inject or absorb **Active Power** in addition to the phase-based **Active Inertia Power** to provide a system with desirable NFP plot characteristics.

**Active Frequency Response Power** can be produced by any viable control technology.

### Active Inertia Power

The injection or absorption of **Active Power** by a Grid Forming Plant to or from the **Total System** during a **System Frequency** change.

The transient injection or absorption of **Active Power** from a Grid Forming Plant to the **Total System** as a result of the **ROCOF** value at the **Grid Entry Point** or **User System Entry Point**. This requires a sufficient energy storage capacity of the Grid Forming Plant to meet the Grid Forming Capability requirements specified in ECC.6.3.19.

For the avoidance of doubt, this includes the rotational inertial energy of the complete drive train of a **Synchronous Generating Unit**.

**Active Inertia Power** is an inherent capability of a Grid Forming Plant to respond naturally, within less than 5ms, to changes in the **System Frequency**.

For the avoidance of doubt, the **Active Inertia Power** has a slower frequency response compared with **Active Phase Jump Power**.
### Active Phase Jump Power

The transient injection or absorption of **Active Power** from a **Grid Forming Plant** to the **Total System** as a result of changes in the phase angle between the **Internal Voltage Source** of the **Grid Forming Plant** and the **Grid Entry Point** or **User System Entry Point**.

In the event of a disturbance or fault on the **Total System**, a **Grid Forming Plant** will instantaneously (within 5ms) inject or absorb **Active Phase Jump Power** to the **Total System** as a result of the phase angle change.

For **GBGF-I** as a minimum value this is up to the **Phase Jump Angle Limit Power**.

**Active Phase Jump Power** is an inherent capability of a **Grid Forming Plant** that starts to respond naturally, within less than 5 ms and can have frequency components of over 1000 Hz.

### 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

### Active ROCOF Response Power

The **Active Inertia Power** developed from a **Grid Forming Plant** plus the **Active Frequency Response Power** that can be supplied by a **Grid Forming Plant** when subject to a rate of change of the **System Frequency**.
<table>
<thead>
<tr>
<th><strong>Additional BM Unit</strong></th>
<th>Has the meaning as set out in the BSC</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Affiliate</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>AF Rules</strong></td>
<td>Has the meaning given to “allocation framework” in section 13(2) of the Energy Act 2013.</td>
</tr>
<tr>
<td><strong>Agency</strong></td>
<td>As defined in The Company’s Transmission Licence.</td>
</tr>
<tr>
<td><strong>Aggregator</strong></td>
<td>A BM Participant who controls one or more Additional BM Units or Secondary BM Units.</td>
</tr>
<tr>
<td><strong>Aggregator Impact Matrix</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Alternate Member</strong></td>
<td>Shall mean an alternate member for the Panel Members elected or appointed in accordance with this GR.7.2(a) or (b).</td>
</tr>
<tr>
<td><strong>Ancillary Service</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Ancillary Services Agreement</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Annual Average Cold Spell Conditions or ACS Conditions</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Apparatus</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Apparent Power</strong></td>
<td>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</td>
</tr>
<tr>
<td><strong>Approved Fast Track Proposal</strong></td>
<td>Has the meaning given in GR.26.7, provided that no objection is received pursuant to GR.26.12.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>-------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Approved Grid Code Self-Governance Proposal</td>
<td>Has the meaning given in GR.24.10.</td>
</tr>
<tr>
<td>Approved Modification</td>
<td>Has the meaning given in GR.22.7</td>
</tr>
<tr>
<td>Authorised Certifier</td>
<td>An entity that issues Equipment Certificates and Power Generating Module Documents and whose accreditation is given by the United Kingdom Accreditation Service or such other body as may be established from time to time to carry out the function of accreditation.</td>
</tr>
<tr>
<td>Authorised Electricity Operator</td>
<td>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.</td>
</tr>
<tr>
<td>Authority-Led Modification</td>
<td>A Grid Code Modification Proposal in respect of a Significant Code Review, raised by the Authority pursuant to GR.17</td>
</tr>
<tr>
<td>Authority-Led Modification Report</td>
<td>Has the meaning given in GR.17.4.</td>
</tr>
<tr>
<td>Authority for Access</td>
<td>An authority which grants the holder the right to unaccompanied access to sites containing exposed HV conductors.</td>
</tr>
<tr>
<td>Authority, The</td>
<td>The Authority established by section 1 (1) of the Utilities Act 2000.</td>
</tr>
<tr>
<td>Automatic Voltage Regulator or AVR</td>
<td>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.</td>
</tr>
<tr>
<td>Auxiliaries</td>
<td>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.</td>
</tr>
<tr>
<td>Auxiliary Diesel Engine</td>
<td>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.</td>
</tr>
<tr>
<td>Auxiliary Gas Turbine</td>
<td>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.</td>
</tr>
<tr>
<td>Average Conditions</td>
<td>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).</td>
</tr>
<tr>
<td>Back-Up Protection</td>
<td>A Protection system which will operate when a system fault is not cleared by other Protection.</td>
</tr>
<tr>
<td><strong>Balancing and Settlement Code or BSC</strong></td>
<td>The code of that title as from time to time amended.</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>--------------------------------------------------</td>
</tr>
<tr>
<td><strong>Balancing Code or BC</strong></td>
<td>That portion of the Grid Code which specifies the Balancing Mechanism process.</td>
</tr>
<tr>
<td><strong>Balancing Mechanism</strong></td>
<td>Has the meaning set out in The Company’s Transmission Licence</td>
</tr>
<tr>
<td><strong>Balancing Mechanism Reporting Agent or BMRA</strong></td>
<td>Has the meaning set out in the BSC.</td>
</tr>
<tr>
<td><strong>Balancing Mechanism Reporting Service or BMRS</strong></td>
<td>Has the meaning set out in the BSC.</td>
</tr>
<tr>
<td><strong>Balancing Principles Statement</strong></td>
<td>A statement prepared by The Company in accordance with Condition C16 of The Company’s Transmission Licence.</td>
</tr>
<tr>
<td><strong>Baseline Forecast</strong></td>
<td>Has the meaning given to the term ‘baseline forecast’ in Section G of the BSC.</td>
</tr>
</tbody>
</table>
| **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 the 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.  
<p>| | 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. |
| <strong>Black Start Contract</strong> | 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; |
| <strong>Black Start HVDC System</strong> | An HVDC System or DC Converter Station which are registered, pursuant to the Bilateral Agreement with a User, as having a Black Start Capability. |
| <strong>Black Start HVDC Test</strong> | 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. |
| <strong>Black Start Service Provider</strong> | A Generator with a Black Start Station or an HVDC System Owner or DC Converter Station Owner with a Black Start HVDC System. |</p>
<table>
<thead>
<tr>
<th>Black Start Stations</th>
<th>Power Stations which are registered, pursuant to the Bilateral Agreement with a User, as having a Black Start Capability.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Start Station Test</td>
<td>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 Synchronous Area.</td>
</tr>
<tr>
<td>Black Start Test</td>
<td>A Black Start Test carried out by 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 comprise a Black Start Station Test, a Black Start Unit Test or Black Start HVDC Test.</td>
</tr>
<tr>
<td>Black Start Unit Test</td>
<td>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.</td>
</tr>
<tr>
<td>Block Loading Capability</td>
<td>The incremental Active Power steps, from no load to Rated MW, which a Generating Unit or Power Generating Module or Power Park Module or 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.</td>
</tr>
<tr>
<td>BM Participant</td>
<td>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.</td>
</tr>
<tr>
<td>BM Unit</td>
<td>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.</td>
</tr>
<tr>
<td>BM Unit Data</td>
<td>The collection of parameters associated with each BM Unit, as described in Appendix 1 of BC1.</td>
</tr>
<tr>
<td>Boiler Time Constant</td>
<td>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 &quot;Dynamic Models for Steam and Hydro Turbines in Power System Studies&quot; published in 1973 which apply to such phrase.</td>
</tr>
<tr>
<td>British Standards or BS</td>
<td>Those standards and specifications approved by the British Standards Institution.</td>
</tr>
<tr>
<td>BSCCo</td>
<td>Has the meaning set out in the BSC.</td>
</tr>
<tr>
<td>BSC Panel</td>
<td>Has meaning set out for “Panel” in the BSC.</td>
</tr>
<tr>
<td>Black Start Unit Test</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Business Day</strong></td>
<td>Any week day (other than a Saturday) on which banks are open for domestic business in the City of London.</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Cancellation of National Electricity Transmission System Warning</strong></td>
<td>The notification given to Users when a National Electricity Transmission System Warning is cancelled.</td>
</tr>
<tr>
<td><strong>Capacity Market Documents</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Capacity Market Rules</strong></td>
<td>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.</td>
</tr>
</tbody>
</table>
| **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  
(c) 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. |
| **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. |

**Caution Notice**
A notice conveying a warning against interference.

**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**

**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 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.
<table>
<thead>
<tr>
<th><strong>CM Administrative Parties</strong></th>
<th>The Secretary of State, the CM Settlement Body, and any CM Settlement Services Provider.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CM Settlement Body</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>CM Settlement Services Provider</strong></td>
<td>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.</td>
</tr>
</tbody>
</table>
| **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; |
<p>| <strong>Code Administrator</strong>       | Means The Company carrying out the role of Code Administrator in accordance with the General Conditions. |
| <strong>Combined Cycle Gas Turbine Module or CCGT Module</strong> | 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. |
| <strong>Combined Cycle Gas Turbine Unit or CCGT Unit</strong> | A Generating Unit within a CCGT Module. |
| <strong>Commercial Ancillary Services</strong> | 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). |
| <strong>Commercial Boundary</strong>       | Has the meaning set out in the CUSC |
| <strong>Committed Level</strong>          | 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. |
| <strong>Committed Project Planning Data</strong> | Data relating to a User Development once the offer for a CUSC Contract is accepted. |</p>
<table>
<thead>
<tr>
<th><strong>Common Collection Busbar</strong></th>
<th>A busbar within a <strong>Power Park Module</strong> to which the higher voltage side of two or more <strong>Power Park Unit</strong> generator transformers are connected.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Completion Date</strong></td>
<td>Has the meaning set out in the <strong>Bilateral Agreement</strong> with each <strong>User</strong> to that term or in the absence of that term to such other term reflecting the date when a <strong>User</strong> is expected to connect to or start using the <strong>National Electricity Transmission System</strong>. In the case of an <strong>Embedded Medium Power Station</strong> or <strong>Embedded DC Converter Station</strong> or <strong>Embedded HVDC System</strong> having a similar meaning in relation to the <strong>Network Operator’s System</strong> as set out in the <strong>Embedded Development Agreement</strong>.</td>
</tr>
<tr>
<td><strong>Complex</strong></td>
<td>A <strong>Connection Site</strong> together with the associated <strong>Power Station</strong> and/or <strong>Network Operator</strong> substation and/or associated <strong>Plant</strong> and/or <strong>Apparatus</strong>, as appropriate.</td>
</tr>
<tr>
<td><strong>Compliance Processes or CP</strong></td>
<td>That portion of the Grid Code which is identified as the <strong>Compliance Processes</strong>.</td>
</tr>
</tbody>
</table>
| **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** and/or **Electricity Storage 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**. |
<p>| <strong>Configuration 1 AC Connected Offshore Power Park Module</strong> | One or more <strong>Offshore Power Park Modules</strong> that are connected to an <strong>AC Offshore Transmission System</strong> and that <strong>AC Offshore Transmission System</strong> is connected to only one <strong>Onshore</strong> substation and which has one or more <strong>Transmission Interface Points</strong>. |</p>
<table>
<thead>
<tr>
<th>Configuration 2 AC Connected Offshore Power Park Module</th>
<th>One or more <strong>Offshore Power Park Modules</strong> that are connected to a meshed <strong>AC Offshore Transmission System</strong> and that <strong>AC Offshore Transmission System</strong> is connected to two or more <strong>Onshore</strong> substations at its <strong>Transmission Interface Points</strong>.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Configuration 1 DC Connected Power Park Module</td>
<td>One or more <strong>DC Connected Power Park Modules</strong> that are connected to an <strong>HVDC System</strong> or <strong>Transmission DC Converter</strong> and that <strong>HVDC System</strong> or <strong>Transmission DC Converter</strong> is connected to only one Onshore substation and which has one or more <strong>Transmission Interface Points</strong>.</td>
</tr>
<tr>
<td>Configuration 2 DC Connected Power Park Module</td>
<td>One or more <strong>DC Connected Power Park Modules</strong> that are connected to an <strong>HVDC System</strong> or <strong>Transmission DC Converter</strong> and that <strong>HVDC System</strong> or <strong>Transmission DC Converter</strong> is connected to more than one Onshore substation at its <strong>Transmission Interface Points</strong>.</td>
</tr>
<tr>
<td>Connection Conditions or CC</td>
<td>That portion of the Grid Code which is identified as the <strong>Connection Conditions</strong> being applicable to <strong>GB Code Users</strong>.</td>
</tr>
<tr>
<td>Connection Entry Capacity</td>
<td>Has the meaning set out in the <strong>CUSC</strong>.</td>
</tr>
<tr>
<td>Connected Planning Data</td>
<td>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 <strong>Forecast Data</strong> items such as <strong>Demand</strong>.</td>
</tr>
<tr>
<td>Connection Point</td>
<td>A <strong>Grid Supply Point</strong> or <strong>Grid Entry Point</strong>, as the case may be.</td>
</tr>
<tr>
<td>Connection Site</td>
<td>A <strong>Transmission Site</strong> or <strong>User Site</strong>, as the case may be.</td>
</tr>
<tr>
<td>Construction Agreement</td>
<td>Has the meaning set out in the <strong>CUSC</strong>.</td>
</tr>
<tr>
<td>Consumer Representative</td>
<td>Means the person appointed by the <strong>Citizens Advice</strong> or the <strong>Citizens Advice Scotland</strong> (or any successor body) representing all categories of customers, appointed in accordance with GR.4.2(b)</td>
</tr>
<tr>
<td>Contingency Reserve</td>
<td>The margin of generation over forecast <strong>Demand</strong> which is required in the period from 24 hours ahead down to real time to cover against uncertainties in <strong>Large Power Station</strong> availability and against both weather forecast and <strong>Demand</strong> forecast errors.</td>
</tr>
<tr>
<td>Control Based Reactive Power</td>
<td>The <strong>Reactive Power</strong> supplied by a <strong>Grid Forming Plant</strong> through controlled means based on operator adjustment selectable setpoints (these may be manual or automatic).</td>
</tr>
<tr>
<td>Control Calls</td>
<td>A telephone call whose destination and/or origin is a key on the control desk telephone keyboard at a <strong>Control Centre</strong> and which, for the purpose of <strong>Control Telephony</strong>, has the right to exercise priority over (ie. disconnect) a call of a lower status.</td>
</tr>
<tr>
<td>Control Centre</td>
<td>A location used for the purpose of control and operation of the <strong>National Electricity Transmission System</strong> or <strong>DC Converter Station</strong> owner's <strong>System</strong> or <strong>HVDC System Owner's System</strong> or a <strong>User System</strong> other than a <strong>Generator's System</strong> or an <strong>External System</strong>.</td>
</tr>
<tr>
<td>Control Engineer</td>
<td>A person nominated by the relevant party for the control of its <strong>Plant</strong> and <strong>Apparatus</strong>.</td>
</tr>
<tr>
<td><strong>Control Person</strong></td>
<td>The term used as an alternative to &quot;Safety Co-ordinator&quot; on the Site Responsibility Schedule only.</td>
</tr>
<tr>
<td><strong>Control Phase</strong></td>
<td>The <strong>Control Phase</strong> follows on from the <strong>Programming Phase</strong> and covers the period down to real time.</td>
</tr>
</tbody>
</table>
| **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; |
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CUSC Framework Agreement</strong></td>
<td>Has the meaning set out in <em>The Company’s Transmission Licence</em>.</td>
</tr>
<tr>
<td><strong>CUSC Party</strong></td>
<td>As defined in the <em>The Company’s Transmission Licence</em> and “CUSC Parties” shall be construed accordingly.</td>
</tr>
<tr>
<td><strong>Customer</strong></td>
<td>A person to whom electrical power is provided (whether or not they are the same person as the person who provides the electrical power).</td>
</tr>
<tr>
<td><strong>Customer Demand Management</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Customer Demand Management Notification Level</strong></td>
<td>The level above which a Supplier has to notify <em>The Company</em> of its proposed or achieved use of Customer Demand Management which is 12 MW in England and Wales and 5 MW in Scotland.</td>
</tr>
<tr>
<td><strong>Customer Generating Plant</strong></td>
<td>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.</td>
</tr>
</tbody>
</table>
| **Damping Factor** (ζ) | The ratio of the actual damping to critical damping.  
For a GBGF-I the open loop phase angle, for an open loop gain of one, is measured from the systems Nichols Chart.  
This angle is used to define the system’s equivalent Damping Factor that is the same as the Damping Factor of a second order system with the same open loop phase angle.  
Alternatively, the Damping Factor refers to the damping of a specific oscillation mode that is associated with the second order system created by the power to angle transfer function as show in Figure PC.A.5.8.1(a) and PCA.5.8.1(b). |
| **Data Publisher** | The person providing a reporting service, in relation to data which is submitted to the reporting service under OC2.4.2.3 or a Transmission Licensee, in relation to data which the Transmission Licensee is required to publish. |
| **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 **GB Code 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 or contractual obligation to provide a service contributing to one or several measures of the **System Defence Plan**. |
| **Defined Active Damping Power** | The **Active Damping Power** supplied by a **GBGF-I** when it is operating at the **Grid Oscillation Value** defined in Table PC.A.5.8.2 |
| **De-Load** | The condition in which a **Genset** has reduced or is not delivering electrical power to the **System** to which it is **Synchronised**. |
| **$\Delta f$** | 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 Constraint 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 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 submitted in accordance with PC.4.4.2 or PC.4.4.4 as applicable. |
| **Disconnection** | The physical separation of **Users** (or **Customers**) from the **National Electricity Transmission System** or a **User System** as the case may be. |
| **Discrimination** | The quality where a relay or protective system is enabled to pick out and cause to be disconnected only the faulty **Apparatus**. |
| **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 **Frequency**), to the per unit steady state change in **Active 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**. |
| **Dynamic Reactive Compensation Equipment** | **Plant** and **Apparatus** capable of injecting or absorbing **Reactive Power** in a controlled manner which includes but is not limited to Synchronous Compensators, Static Var Compensators (SVC), or STATCOM devices. |
| **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 |
<p>| <strong>Electrical Standard</strong> | A standard listed in the Annex to the General Conditions. |
| <strong>Electricity Balancing Regulation</strong> | as defined in the CUSC. |
| <strong>Electricity Council</strong> | That body set up under the Electricity Act, 1957. |
| <strong>Electricity Distribution Licence</strong> | The licence granted pursuant to Section 6(1) (c) of the Act. |
| <strong>Electricity Regulation</strong> | As defined in the Transmission Licence. |
| <strong>Electricity Storage</strong> | 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. |
| <strong>Electricity Storage Module</strong> | 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. |
| <strong>Electricity Storage Unit</strong> | A Synchronous Electricity Storage Unit or Non-Synchronous Electricity Storage Unit. |
| <strong>Electricity Supply Industry Arbitration Association</strong> | 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. |
| <strong>Electricity Supply Licence</strong> | The licence granted pursuant to Section 6(1) (d) of the Act. |
| <strong>Electromagnetic Compatibility Level</strong> | Has the meaning set out in Engineering Recommendation G5. |
| <strong>Electronic Power Converter</strong> | Electrical Plant and Apparatus which uses switched solid state power electronic devices to produce a real voltage waveform, that has a fundamental component with harmonics. |
| <strong>Embedded</strong> | 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). |
| <strong>Embedded Development</strong> | Has the meaning set out in PC.4.4.3(a). |
| <strong>Embedded Development Agreement</strong> | 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. |
| <strong>Embedded Generation Control</strong> | Any or all of the following methods by which a Network Operator can achieve a reduction in the Active Power output of Embedded Power Stations to implement an instruction issued by The Company: |
| (a) <strong>Embedded Generation De-energisation</strong>; or |
| (b) where this is achievable in a suitable timescale to comply with an instruction, arranging to reduce the Active Power output of Embedded Power Stations or Embedded Generator Unit(s) connected to their System. |
| <strong>Embedded Generation Deenergisation</strong> | The de-energisation by Network Operators of one or more Embedded Power Stations or Embedded Generating Units from their System as part of an Embedded Generation Control action. |
| <strong>Embedded Person</strong> | 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. |
| <strong>Emergency Deenergisation Instruction</strong> | 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. |
| <strong>Emergency Instruction</strong> | 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. |</p>
<table>
<thead>
<tr>
<th><strong>EMR Administrative Parties</strong></th>
<th>Has the meaning given to “administrative parties” in The Electricity Capacity Regulations 2014 and each CfD Counterparty and CfD Settlement Services Provider.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>EMR Documents</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>EMR Functions</strong></td>
<td>Has the meaning given to “EMR functions” in Chapter 5 of Part 2 of the Energy Act 2013.</td>
</tr>
<tr>
<td><strong>Engineering Recommendations</strong></td>
<td>The documents referred to as such and issued by the Energy Networks Association or the former Electricity Council.</td>
</tr>
<tr>
<td><strong>Engineering Recommendation G5</strong></td>
<td>Means Engineering Recommendation G5/5.</td>
</tr>
<tr>
<td><strong>Energisation Operational Notification or EON</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Equipment Certificate</strong></td>
<td>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 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.</td>
</tr>
<tr>
<td><strong>Estimated Registered Data</strong></td>
<td>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.</td>
</tr>
<tr>
<td>EU Code User</td>
<td>A User who is any of the following:-</td>
</tr>
<tr>
<td>--------------</td>
<td>-------------------------------------</td>
</tr>
<tr>
<td>(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</td>
<td></td>
</tr>
<tr>
<td>(b) 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.</td>
<td></td>
</tr>
<tr>
<td>(c) 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.</td>
<td></td>
</tr>
<tr>
<td>(d) 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.</td>
<td></td>
</tr>
<tr>
<td>(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.</td>
<td></td>
</tr>
<tr>
<td>(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.</td>
<td></td>
</tr>
<tr>
<td>(g) A User which the Authority has determined should be considered as an EU Code User.</td>
<td></td>
</tr>
<tr>
<td>(h) 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.</td>
<td></td>
</tr>
<tr>
<td>(i) 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.</td>
<td></td>
</tr>
<tr>
<td>(j) Storage User in respect of an Electricity Storage Module whose Main Plant and Apparatus is connected to the System on or after 20 May 2020 and who concluded Purchase</td>
<td></td>
</tr>
<tr>
<td><strong>Contracts for its Main Plant and Apparatus</strong> on or after 20 May 2019.</td>
<td></td>
</tr>
<tr>
<td>---</td>
<td></td>
</tr>
<tr>
<td><strong>EU Generator</strong></td>
<td>A Generator or OTSDUA who is also an EU Code User.</td>
</tr>
</tbody>
</table>
| **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 relevant 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 Retained EU Law (Commission Regulation (EU) 543/2013), 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 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 BS4999 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 BS4999 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 BS4999 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 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  
| 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 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.  
| 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](#).  

[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  

[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 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.  

[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](#).
<p>| 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 Response Deadband | An interval used intentionally to make the Frequency control unresponsive. |
| Frequency Response 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. |
| Frequency Restoration Reserves (FRR) | Means, in the context of Balancing Services, the Active Power reserves available to restore System Frequency to the nominal Frequency. |
| 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. |
| <strong>Frequency Sensitive AGR Unit Limit</strong> | 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. |
| <strong>Frequency Sensitive Mode</strong> | 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. |
| <strong>Fuel Security Code</strong> | The document of that title designated as such by the Secretary of State, as from time to time amended. |
| <strong>Gas Turbine Unit</strong> | A Generating Unit driven by a gas turbine (for instance by an aero-engine). |
| <strong>Gas Zone Diagram</strong> | 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. |
| <strong>Gate Closure</strong> | Has the meaning set out in the BSC. |</p>
<table>
<thead>
<tr>
<th>GB Code User</th>
<th>A User in respect of:-</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(a) A Generator or OTSDUA whose Main Plant and Apparatus (excluding a DC Connected Power Park Module) 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</td>
</tr>
<tr>
<td></td>
<td>(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</td>
</tr>
<tr>
<td></td>
<td>(c) A Non-Embedded Customer whose Main Plant and Apparatus was connected to the National Electricity Transmission System at a GB Grid Supply Point before 18 August 2019 or who had placed Purchase Contracts for its Main Plant and Apparatus before 7 September 2018 or that Non-Embedded Customer is not the subject of a Substantial Modification which is effective on or after 18 August 2019; or</td>
</tr>
<tr>
<td></td>
<td>(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.</td>
</tr>
</tbody>
</table>

<p>| GB Generator | A Generator, or OTSDUA, who is also a GB Code User. |
| GBGF Fast Fault Current Injection | The ability of a Grid Forming Plant to supply reactive current, that starts to be delivered into the Total System in less than 5ms when the voltage falls below 90% of its nominal value at the Grid Entry Point or User System Entry Point. |
| GB Grid Forming - Inverter or GBGF-I | Is any Power Park Module, HVDC System, DC Converter, OTSDUW Plant and Apparatus, Non-Synchronous Electricity Storage Module, Dynamic Reactive Compensation Equipment or any Plant and Apparatus (including a smart load) which is connected or partly connected to the Total System via an Electronic Power Converter which has a Grid Forming Capability (GBGF-I). |
| GB Grid Forming – Synchronous or GBGF-S | Is a Synchronous Power Generating Module, Synchronous Electricity Storage Module or Synchronous Generating Unit with a Grid Forming Capability. |</p>
<table>
<thead>
<tr>
<th><strong>GB Grid Supply Point</strong></th>
<th>A Grid Supply Point which is not an EU Grid Supply Point.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>GB Synchronous Area</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>GCDF</strong></td>
<td>Means the Grid Code Development Forum.</td>
</tr>
<tr>
<td><strong>General Conditions or GC</strong></td>
<td>That portion of the Grid Code which is identified as the General Conditions.</td>
</tr>
<tr>
<td><strong>Generating Plant Demand Margin</strong></td>
<td>The difference between Output Usable and forecast Demand.</td>
</tr>
<tr>
<td><strong>Generating Unit</strong></td>
<td>An Onshore Generating Unit and/or an Offshore Generating Unit which could also be part of a Power Generating Module.</td>
</tr>
</tbody>
</table>
| **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. |
<p>| <strong>Generation Capacity</strong>  | Has the meaning set out in the BSC. |
| <strong>Generation Planning Parameters</strong> | Those parameters listed in Appendix 2 of OC2. |
| <strong>Generator</strong>           | A person who generates electricity or undertakes Electricity Storage 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. |
| <strong>Generator Performance Chart</strong> | A diagram which shows the MW and MVAr capability limits within which a Generating Unit will be expected to operate under steady state conditions. |
| <strong>Genset</strong>              | A Power Generating Module (including a DC Connected Power Park Module and/or Electricity Storage 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. |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Good Industry Practice</td>
<td>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.</td>
</tr>
<tr>
<td>Governance Rules or GR</td>
<td>That portion of the Grid Code which is identified as the Governance Rules.</td>
</tr>
<tr>
<td>Governor Deadband</td>
<td>An interval used intentionally to make the frequency control unresponsive.</td>
</tr>
<tr>
<td>Great Britain or GB</td>
<td>The landmass of England and Wales and Scotland, including internal waters.</td>
</tr>
<tr>
<td>Grid Code Fast Track Proposals</td>
<td>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.</td>
</tr>
<tr>
<td>Grid Code Modification Fast Track Report</td>
<td>A report prepared pursuant to GR.26</td>
</tr>
<tr>
<td>Grid Code Modification Register</td>
<td>Has the meaning given in GR.13.1.</td>
</tr>
<tr>
<td>Grid Code Modification Report</td>
<td>Has the meaning given in GR.22.1.</td>
</tr>
<tr>
<td>Grid Code Modification Procedures</td>
<td>The procedures for the modification of the Grid Code (including the implementation of Approved Modifications) as set out in the Governance Rules.</td>
</tr>
<tr>
<td>Grid Code Modification Proposal</td>
<td>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.</td>
</tr>
<tr>
<td>Grid Code Modification Self-Governance Report</td>
<td>Has the meaning given in GR.24.5</td>
</tr>
<tr>
<td>Grid Code Objectives</td>
<td>Means the objectives referred to in Paragraph 1b of Standard Condition C14 of The Company’s Transmission Licence.</td>
</tr>
<tr>
<td>Grid Code Review Panel or Panel</td>
<td>The panel with the functions set out in GR.1.2.</td>
</tr>
<tr>
<td>Grid Code Review Panel Recommendation Vote</td>
<td>The vote of Panel Members undertaken by the Panel Chairperson 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.</td>
</tr>
<tr>
<td>Grid Code Review Panel Self-Governance Vote</td>
<td>The vote of Panel Members undertaken by the Panel Chairperson 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).</td>
</tr>
<tr>
<td>Grid Entry Point</td>
<td>An Onshore Grid Entry Point or an Offshore Grid Entry Point.</td>
</tr>
<tr>
<td>Grid Forming Active Power</td>
<td>Grid Forming Active Power is the inherent Active Power produced by Grid Forming Plant that includes Active Inertia Power plus Active Phase Jump Power plus Active Damping Power.</td>
</tr>
<tr>
<td>Grid Forming Capability</td>
<td>Is (but not limited to) the capability a Power Generating Module, HVDC Converter (which could form part of an HVDC System), Generating Unit, Power Park Module, DC Converter, OTSDUW Plant and Apparatus, Electricity Storage Module, Dynamic Reactive Compensation Equipment or any Plant and Apparatus (including a smart load) whose supplied Active Power is directly proportional to the difference between the magnitude and phase of its Internal Voltage Source and the magnitude and phase of the voltage at the Grid Entry Point or User System Entry Point and the sine of the Load Angle. As a consequence, Plant and Apparatus which has a Grid Forming Capability has a frequency of rotation of the Internal Voltage Source which is the same as the System Frequency for normal operation, with only the Load Angle defining the relative position between the two. In the case of a GBGF-I, a Grid Forming Unit forming part of a GBGF-I shall be capable of sustaining a voltage at its terminals irrespective of the voltage at the Grid Entry Point or User System Entry Point for normal operating conditions. For GBGF-I, the control system, which determines the amplitude and phase of the Internal Voltage Source, shall have a response to the voltage and System Frequency at the Grid Entry Point or User System Entry Point) with a bandwidth that is less than a defined value as shown by the control system’s NFP Plot. Exceptions to this requirement are only allowed during transients caused by System faults, voltage dips/surges and/or step or ramp changes in the phase angle which are large enough to cause damage to the Grid Forming Plant via excessive currents.</td>
</tr>
<tr>
<td>Grid Forming Electronic Power Converter</td>
<td>A Grid Forming Plant whose output is derived from an Electronic Power Converter with a GBGF-I capability.</td>
</tr>
<tr>
<td>Grid Forming Plant</td>
<td>A site which contains Plant and Apparatus which is classified as either a GBGF-S or a GBGF-I</td>
</tr>
<tr>
<td>Grid Forming Plant Owner</td>
<td>The owner or operator of a Grid Forming Plant.</td>
</tr>
<tr>
<td>Grid Forming Unit</td>
<td>A Power Park Unit or Electricity Storage Unit or a Synchronous Power Generating Unit or individual Load with a Grid Forming Capability.</td>
</tr>
<tr>
<td>Grid Oscillation Value</td>
<td>An injected test frequency signal applied at nominal System Frequency with a superimposed oscillatory response overlayed onto the nominal System Frequency with an amplitude of 0.05 Hz peak to peak at a frequency of 1 Hz and is used for determining the rating of the Defined Active Damping Power.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Grid Supply Point</td>
<td>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.</td>
</tr>
<tr>
<td>Group</td>
<td>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.</td>
</tr>
<tr>
<td>GSP Group</td>
<td>Has the meaning as set out in the BSC.</td>
</tr>
<tr>
<td>Headroom</td>
<td>The Power Available (in MW) less the actual Active Power exported from the Power Park Module (in MW).</td>
</tr>
<tr>
<td>High Frequency Response</td>
<td>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 and Figure ECC.A.3.3.</td>
</tr>
<tr>
<td>High Voltage or HV</td>
<td>For E&amp;W Transmission Systems, a voltage exceeding 650 volts. For Scottish Transmission Systems, a voltage exceeding 1000 volts.</td>
</tr>
<tr>
<td>Historic Frequency Data</td>
<td>System Frequency data at a maximum of one second intervals for the whole month, published by The Company as detailed in OC3.4.4.</td>
</tr>
<tr>
<td>Houseload Operation</td>
<td>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.</td>
</tr>
<tr>
<td>HP Turbine Power Fraction</td>
<td>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.</td>
</tr>
<tr>
<td>HV Connections</td>
<td>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.</td>
</tr>
<tr>
<td>HVDC Converter</td>
<td>Any EU Code User Apparatus used to convert alternating current electricity to direct current electricity, or vice versa. An HVDC Converter 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.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>------------------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>HVDC Converter Station</td>
<td>Part of an <strong>HVDC System</strong> which consists of one or more <strong>HVDC Converters</strong> installed in a single location together with buildings, reactors, filters reactive power devices, control, monitoring, protective, measuring and auxiliary equipment.</td>
</tr>
<tr>
<td>HVDC Equipment</td>
<td>Collectively means an <strong>HVDC System</strong> and a <strong>DC Connected Power Park Module</strong> and a <strong>Remote End HVDC Converter Station</strong>.</td>
</tr>
<tr>
<td>HVDC Interface Point</td>
<td>A point at which <strong>HVDC Plant</strong> and <strong>Apparatus</strong> is connected to an <strong>AC System</strong> at which technical specifications affecting the performance of the Plant and Apparatus can be prescribed.</td>
</tr>
<tr>
<td>HVDC System</td>
<td>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 <strong>HVDC Converter Stations</strong> with DC Transmission lines or cables between the <strong>HVDC Converter Stations</strong>.</td>
</tr>
<tr>
<td>HVDC System Owner</td>
<td>A party who owns and is responsible for an <strong>HVDC System</strong>. For the avoidance of doubt a <strong>DC Connected Power Park Module</strong> owner would be treated as a <strong>Generator</strong>.</td>
</tr>
<tr>
<td>IEC</td>
<td>International Electrotechnical Commission.</td>
</tr>
<tr>
<td>IEC Standard</td>
<td>A standard approved by the International Electrotechnical Commission.</td>
</tr>
<tr>
<td>Implementation Date</td>
<td>Is the date and time for implementation of an <strong>Approved Modification</strong> as specified in accordance with Paragraph GR.25.3.</td>
</tr>
<tr>
<td>Implementing Safety Co-ordinator</td>
<td>The <strong>Safety Co-ordinator</strong> implementing <strong>Safety Precautions</strong>.</td>
</tr>
<tr>
<td>Import Usable</td>
<td>That portion of <strong>Registered Import Capacity</strong> which is expected to be available and which is not unavailable due to a <strong>Planned Outage</strong>.</td>
</tr>
<tr>
<td>Incident Centre</td>
<td>A centre established by <strong>The Company</strong> or a <strong>User</strong> as the focal point in <strong>The Company</strong> or in that <strong>User</strong>, as the case may be, for the communication and dissemination of information between the senior management representatives of <strong>The Company</strong>, or of that <strong>User</strong>, as the case may be, and the relevant other parties during a <strong>Joint System Incident</strong> in order to avoid overloading <strong>The Company’s</strong>, or that <strong>User’s</strong>, as the case may be, existing operational/control arrangements.</td>
</tr>
<tr>
<td>Independent Back-Up Protection</td>
<td>A <strong>Back-Up Protection</strong> system which utilises a discrete relay, different current transformers and an alternate operating principle to the <strong>Main Protection</strong> systems(s) such that it can operate autonomously in the event of a failure of the <strong>Main Protection</strong>.</td>
</tr>
<tr>
<td>Independent Main Protection</td>
<td>A <strong>Main Protection</strong> system which utilises a physically discrete relay and different current transformers to any other <strong>Main Protection</strong>.</td>
</tr>
<tr>
<td>Indicated Constraint Boundary Margin</td>
<td>The difference between a constraint boundary transfer limit and the difference between the sum of <strong>BM Unit Maximum Export Limits</strong> and the forecast of local <strong>Demand</strong> within the constraint boundary.</td>
</tr>
<tr>
<td>Indicated Imbalance</td>
<td>The difference between the sum of <strong>Physical Notifications</strong> for <strong>BM Units</strong> comprising <strong>Generating Units</strong> or <strong>CCGT Modules</strong> or <strong>Power Generating Modules</strong> and the forecast of <strong>Demand</strong> for the whole or any part of the <strong>System</strong>.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
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<td>------------</td>
</tr>
<tr>
<td>Indicated Margin</td>
<td>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.</td>
</tr>
<tr>
<td>Inertia Constant H</td>
<td>For a GBGF-S the Inertia Constant H is measured in MWsec/MVA.</td>
</tr>
<tr>
<td>Inertia Constant He</td>
<td>For a GBGF- I Electronic Power Converter the Inertia Constant He, is measured in MWsec/MVA and produced by the Active ROCOF Response Power.</td>
</tr>
<tr>
<td>Installation Document</td>
<td>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</td>
</tr>
<tr>
<td>Instructor Facilities</td>
<td>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.</td>
</tr>
<tr>
<td>Integral Equipment Test or IET</td>
<td>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.</td>
</tr>
<tr>
<td>Intellectual Property” or “IPRs</td>
<td>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.</td>
</tr>
<tr>
<td>Interconnection Agreement</td>
<td>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.</td>
</tr>
<tr>
<td>Interconnector Export Capacity</td>
<td>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.</td>
</tr>
<tr>
<td>Interconnector Import Capacity</td>
<td>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.</td>
</tr>
<tr>
<td>Interconnector Owner</td>
<td>Has the meaning given to the term in the Connection and Use of System Code.</td>
</tr>
<tr>
<td>Interconnector User</td>
<td>Has the meaning set out in the BSC.</td>
</tr>
<tr>
<td>Interface Agreement</td>
<td>Has the meaning set out in the CUSC.</td>
</tr>
</tbody>
</table>
| **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*. |
<table>
<thead>
<tr>
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<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Interface Point Capacity</strong></td>
<td>The maximum amount of <em>Active Power</em> transerable at the <em>Interface Point</em> as declared by a <em>User</em> under the <em>OTSDUW Arrangements</em> expressed in whole MW.</td>
</tr>
<tr>
<td><strong>Interface Point Target Voltage/Power factor</strong></td>
<td>The nominal target voltage/power factor at an <em>Interface Point</em> which a <em>Network Operator</em> requires <em>The Company</em> to achieve by operation of the relevant <em>Offshore Transmission System</em>.</td>
</tr>
</tbody>
</table>
| **Interim Operational Notification or ION** | A notification from *The Company* to a *Generator* or *DC Converter Station owner* or *HVDC System Owner* 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* or *ECP*. |
| **Intermittent Power Source** | The primary source of power for a *Generating Unit* or *Power Generating Module* that cannot be considered as controllable, e.g. wind, wave or solar. For the avoidance of doubt, the output from an *Electricity Storage Module* would not be considered to be an *Intermittent Power Source*. |
| **Internal Voltage Source or IVS** | For a *GBGF-S*, a real magnetic field, that rotates synchronously with the *System Frequency* under normal operating conditions, which as a consequence induces an internal voltage (which is often referred to as the Electro Motive Force (EMF)) in the stationary generator winding that has a real impedance.  
  In a *GBGF-I*, switched power electronic devices are used to produce a voltage waveform, with harmonics, that has a fundamental rotational component called the *Internal Voltage Source (IVS)* that rotates synchronously with the *System Frequency* under normal operating conditions.  
  For a *GBGF-I* there must be an impedance with only real physical values, between the *Internal Voltage Source* and the *Grid Entry Point* or *User System Entry Point*.  
  For the avoidance of doubt, a virtual impedance, is not permitted in *GBGF-I*. |
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Intertripping</strong></td>
<td>(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.</td>
</tr>
<tr>
<td><strong>Intertrip Apparatus</strong></td>
<td>Apparatus which performs Intertripping.</td>
</tr>
<tr>
<td><strong>IP Turbine Power Fraction</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Isolating Device</strong></td>
<td>A device for achieving Isolation.</td>
</tr>
<tr>
<td><strong>Isolation</strong></td>
<td>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:</td>
</tr>
<tr>
<td></td>
<td>(a) an Isolating Device maintained in an isolating position. The isolating position must either be:</td>
</tr>
<tr>
<td></td>
<td>(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</td>
</tr>
<tr>
<td></td>
<td>(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</td>
</tr>
<tr>
<td><strong>Joint System Incident</strong></td>
<td>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).</td>
</tr>
<tr>
<td><strong>Key Safe</strong></td>
<td>A device for the secure retention of keys.</td>
</tr>
<tr>
<td>Key Safe Key</td>
<td>A key unique at a <strong>Location</strong> capable of operating a lock, other than a control lock, on a <strong>Key Safe</strong>.</td>
</tr>
</tbody>
</table>
| 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;  
(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;  
(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**. |
<p>| Legally Binding Decisions of the European Commission and/or the Agency | Any relevant legally binding decision or decisions of the European Commission and/or the <strong>Agency</strong>, but a binding decision does not include a decision that is not, or so much of a decision as is not, <strong>Retained EU Law</strong>. |
| Legal Challenge | Where permitted by law, a judicial review in respect of the <strong>Authority’s</strong> decision to approve or not to approve a <strong>Grid Code Modification Proposal</strong>. |
| Licence | Any licence granted to <strong>The Company</strong> or a <strong>Relevant Transmission Licensee</strong> or a <strong>User</strong>, under Section 6 of the <strong>Act</strong>. |</p>
<table>
<thead>
<tr>
<th><strong>Licence Standards</strong></th>
<th>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.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Limited Frequency Sensitive Mode</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Limited Frequency Sensitive Mode – Overfrequency or LFSM-O</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Limited Frequency Sensitive Mode – Underfrequency or LFSM-U</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Limited High Frequency Response</strong></td>
<td>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.</td>
</tr>
</tbody>
</table>
| **Limited Membership Workgroup** | A Workgroup having less than five (5) but more than two (2) persons that have nominated themselves for membership in addition to the Code Administrator representative and the chairperson of the Workgroup.  
Members of a Limited Membership Workgroup where employed by companies that are considered to be an Affiliate of each other will be considered to be a single workgroup member for the purposes of fulfilling this minimum requirement. |
| **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. |
<p>| <strong>Load</strong> | The Active, Reactive or Apparent Power, as the context requires, generated, transmitted or distributed. |
| <strong>Loaded</strong> | Supplying electrical power to the System. |</p>
<table>
<thead>
<tr>
<th><strong>Load Angle</strong></th>
<th>The angle in radians between the voltage of the <strong>Internal Voltage Source</strong> and the voltage at the <strong>Grid Entry Point</strong> or <strong>User System Entry Point</strong>.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Load Factor</strong></td>
<td>The ratio of the actual output of a <strong>Generating Unit</strong> or <strong>Power Generating Module</strong> to the possible maximum output of that <strong>Generating Unit</strong> or <strong>Power Generating Module</strong>.</td>
</tr>
<tr>
<td><strong>Load Management Block</strong></td>
<td>A block of <strong>Demand</strong> controlled by a <strong>Supplier</strong> or other party through the means of radio teleswitching or by some other means.</td>
</tr>
</tbody>
</table>
| **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 **NGE’s** or **User’s** relevant manager, setting down the methods of achieving the objectives of **NGE’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 their **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** | 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. |
| **Active Power Margin** or **Localised NRAPM** | **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** and **Electricity Storage Modules**) is one or more of the principal items of **Plant** or **Apparatus** required to convert or re-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**.
<table>
<thead>
<tr>
<th><strong>Maximum Export Capacity</strong></th>
<th>The maximum continuous <strong>Apparent Power</strong> expressed in MVA and maximum continuous <strong>Active Power</strong> expressed in MW which can flow from an <strong>Offshore Transmission System</strong> connected to a <strong>Network Operator’s User System</strong>, to that User System.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum Capacity or P_max</strong></td>
<td>The maximum continuous <strong>Active Power</strong> which a <strong>Power Generating Module</strong> can supply to the <strong>Total System</strong>, less any demand associated solely with facilitating the operation of that <strong>Power Generating Module</strong> and not fed into the <strong>System</strong>. In the case of an <strong>Electricity Storage Module</strong>, the <strong>Maximum Capacity</strong> is the maximum continuous <strong>Active Power</strong> which an <strong>Electricity Storage Module</strong> can export to the <strong>Total System</strong> less any demand associated with facilitating the operation of that <strong>Electricity Storage Module</strong> when fully charged and operating in a mode analogous to <strong>Generation</strong>.</td>
</tr>
<tr>
<td><strong>Maximum Generation Service or MGS</strong></td>
<td>A service utilised by <strong>The Company</strong> in accordance with the <strong>CUSC</strong> and the <strong>Balancing Principles Statement</strong> in operating the <strong>Total System</strong>.</td>
</tr>
<tr>
<td><strong>Maximum Generation Service Agreement</strong></td>
<td>An agreement between a <strong>User</strong> and <strong>The Company</strong> for the payment by <strong>The Company</strong> to that <strong>User</strong> in respect of the provision by such <strong>User</strong> of a <strong>Maximum Generation Service</strong>.</td>
</tr>
<tr>
<td><strong>Maximum HVDC Active Power Transmission Capacity (PHmax)</strong></td>
<td>The maximum continuous <strong>Active Power</strong> which an <strong>HVDC System</strong> can exchange with the network at each <strong>Grid Entry Point</strong> or <strong>User System Entry Point</strong> as specified in the <strong>Bilateral Agreement</strong> or as agreed between <strong>The Company</strong> and the <strong>HVDC System Owner</strong>.</td>
</tr>
<tr>
<td><strong>Maximum Import Capability</strong></td>
<td>The maximum continuous <strong>Active Power</strong> that a <strong>Network Operator</strong> or <strong>Non-Embedded Customer</strong> can import from the <strong>Transmission System</strong> at the <strong>Grid Supply Point</strong>, as specified in the <strong>Bilateral Agreement</strong>.</td>
</tr>
<tr>
<td><strong>Maximum Import Capacity</strong></td>
<td>The maximum continuous <strong>Apparent Power</strong> expressed in MVA and maximum continuous <strong>Active Power</strong> expressed in MW which can flow to an <strong>Offshore Transmission System</strong> connected to a <strong>Network Operator’s User System</strong>, from that <strong>User System</strong>.</td>
</tr>
<tr>
<td><strong>Maximum Import Power</strong></td>
<td>The maximum continuous <strong>Active Power</strong> which an <strong>Electricity Storage Module</strong> can import from the <strong>Total System</strong>, when fully discharged and operating in a mode analogous to <strong>Demand</strong>.</td>
</tr>
</tbody>
</table>
| 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. |
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Medium Voltage or MV</td>
<td>For E&amp;W Transmission Systems a voltage exceeding 250 volts but not exceeding 650 volts.</td>
</tr>
<tr>
<td>Mills</td>
<td>Milling plant which supplies pulverised fuel to the boiler of a coal fired Power Station.</td>
</tr>
<tr>
<td>Minimum Generation</td>
<td>The minimum output (in whole MW) which a Genset can generate or DC Converter at a DC Converter Station or Electricity Storage Module 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.</td>
</tr>
<tr>
<td>Minimum Active Power Transmission Capacity (PHmin)</td>
<td>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.</td>
</tr>
<tr>
<td>Minimum Import Capacity</td>
<td>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).</td>
</tr>
<tr>
<td>Minimum Regulating Level</td>
<td>The minimum Active Power, as specified in the Bilateral Agreement or as agreed between The Company and the Generator or HVDC System Owner, down to which the Power Generating Module (including a DC Connected Power Park Module) or HVDC System can control Active Power.</td>
</tr>
<tr>
<td><strong>Minimum Stable Operating Level</strong></td>
<td>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.</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Modification</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed DC Connected Power Park Module</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed DC Converter at a DC Converter Station</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed HVDC System</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed HVDC Converter</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed Generating Unit</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed Power Generating Module</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Mothballed Power Park Module</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Multiple Point of Connection</strong></td>
<td>A double (or more) Point of Connection, being two (or more) Points of Connection interconnected to each other through the User’s System.</td>
</tr>
<tr>
<td><strong>MSID</strong></td>
<td>Has the meaning a set out in the BSC, covers Metering System Identifier.</td>
</tr>
<tr>
<td>National Demand</td>
<td>The amount of electricity supplied from the Grid Supply Points plus:-</td>
</tr>
<tr>
<td>-----------------</td>
<td>---------------------------------------------------------------------</td>
</tr>
<tr>
<td></td>
<td>• that supplied by Embedded Large Power Stations, and</td>
</tr>
<tr>
<td></td>
<td>• National Electricity Transmission System Losses,</td>
</tr>
<tr>
<td></td>
<td>minus:-</td>
</tr>
<tr>
<td></td>
<td>• the Demand taken by Station Transformers and, Pumped Storage Units’ and Electricity Storage Modules’.</td>
</tr>
<tr>
<td></td>
<td>and, for the purposes of this definition, does not include:-</td>
</tr>
<tr>
<td></td>
<td>• any exports from the National Electricity Transmission System across External Interconnections.</td>
</tr>
</tbody>
</table>


<table>
<thead>
<tr>
<th>National Electricity Transmission System Demand</th>
<th>The amount of electricity supplied from the Grid Supply Points plus:-</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>• that supplied by Embedded Large Power Stations, and</td>
</tr>
<tr>
<td></td>
<td>• exports from the National Electricity Transmission System across External Interconnections, and</td>
</tr>
<tr>
<td></td>
<td>• National Electricity Transmission System Losses,</td>
</tr>
<tr>
<td></td>
<td>and, for the purposes of this definition, includes:-</td>
</tr>
<tr>
<td></td>
<td>• the Demand taken by Station Transformers and, Pumped Storage Units and Electricity Storage Modules’.</td>
</tr>
</tbody>
</table>

| 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. |

<table>
<thead>
<tr>
<th>National Electricity Transmission System Warning</th>
<th>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:</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(a) alert Users to possible or actual Plant shortage, System problems and/or Demand reductions;</td>
</tr>
<tr>
<td></td>
<td>(b) inform of the applicable period;</td>
</tr>
<tr>
<td></td>
<td>(c) indicate intended consequences for Users; and</td>
</tr>
<tr>
<td></td>
<td>(d) enable specified Users to be in a state of readiness to receive instructions from The Company.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning - Demand Control Imminent</td>
<td>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.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning - Electricity Margin Notice</td>
<td>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.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – Embedded Generation Control Imminent</td>
<td>A warning issued by The Company, in accordance with OC7.4.8.12, which is intended to provide short term notice, where possible, to those Network Operators who are likely to receive Embedded Generation Control instructions from The Company within 30 minutes.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning - High Risk of Demand Reduction</td>
<td>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.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction</td>
<td>A warning issued by The Company, in accordance with OC7.4.8.11, which is intended to alert recipients that there is a high risk of Embedded Generation Control being implemented and which may result from a National Electricity Transmission System Warning – System NRAPM.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – Localised NRAPM</td>
<td>A warning issued by The Company, in accordance with OC7.4.8.10, which is intended to invite a response from and to alert recipients to a decreased Localised NRAPM.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning - Risk of System Disturbance</td>
<td>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.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – System NRAPM</td>
<td>A warning issued by The Company, in accordance with OC7.4.8.9, which is intended to invite a response from and to alert recipients to a decreased System NRAPM.</td>
</tr>
<tr>
<td>Network Data</td>
<td>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.</td>
</tr>
</tbody>
</table>
### Network Frequency Perturbation Plot
A form of Bode Plot which plots the amplitude (%) and phase (degrees) of the resulting output oscillation responding to an applied input oscillation across a frequency base. The plot will be used to assess the capability and performance of a **Grid Forming Plant** and to ensure that it does not pose a risk to other **Plant and Apparatus** connected to the **Total System**.

For **GBGF-I**, these are used to provide data to **The Company** which together with the associated **Nichols Chart** (or equivalent) defines the effects on a **GBGF-I** for changes in the frequency of the applied input oscillation.

The input is the applied as an input oscillation and the output is the resulting oscillations in the **GBGF-I's Active Power**.

For the avoidance of doubt, **Generators** in respect of **GBGF-S** can provide their data using the existing formats and do not need to supply **NFP plots**.

### 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.

### Nichols Chart
For a **GBGF-I**, a chart derived from the open loop Bode Plots that are used to produce an **NFP Plot**. The **Nichols Chart** plots open loop gain versus open loop phase angle. This enables the open loop phase for an open loop gain of 1 to be identified for use in defining the **GBGF-I's** equivalent **Damping Factor**.

### No-Load Field Voltage
Shall have the meaning ascribed to that term in **IEC 34-16-1:1991** [equivalent to **British Standard BS4999 Section 116.1 : 1992**].

### No System Connection
As defined in OC8A.1.6.2 and OC8B.1.7.2.

### Non-CUSC Party
A Party who does not accede to the **Connection and Use of System Code** (CUSC).

### Non-Synchronous Electricity Storage Module
A **Power Park Module** comprising solely 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-Controllable Electricity Storage Equipment

An item of storage **Plant**, including but not limited to a **Synchronous Flywheel** or **Synchronous Compensation Equipment** or **Regenerative Braking** whose active output power cannot be independently controlled.

### 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 Electricity Storage Module

A **Power Park Module** comprising solely of one or more **Non-Synchronous Electricity Storage Units**.

### Non-Synchronous Electricity Storage Unit

A **Power Park Unit** which can produce electrical energy by converting or re-converting another source of energy such that the frequency of the generated voltage is not inherently in synchronism with the frequency of the **System**.

### 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.
<table>
<thead>
<tr>
<th>Offshore Development Information Statement</th>
<th>A statement prepared by The Company in accordance with Special Condition C4 of The Company’s Transmission Licence.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Offshore Generating Unit</td>
<td>Unless otherwise provided in the Grid Code, any Apparatus located Offshore which produces electrical energy by converting or re-converting another source of energy, including, an Offshore Synchronous Generating Unit or Offshore Non-Synchronous Generating Unit which could also be part of a Power Generating Module or Electricity Storage Module</td>
</tr>
<tr>
<td>Offshore Grid Entry Point</td>
<td>In the case of:-</td>
</tr>
<tr>
<td></td>
<td>(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;</td>
</tr>
<tr>
<td></td>
<td>(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;</td>
</tr>
<tr>
<td></td>
<td>(c) an External Interconnection which is directly connected to an Offshore Transmission System, the point at which it connects to that Offshore Transmission System.</td>
</tr>
<tr>
<td>Offshore Non-Synchronous Generating Unit</td>
<td>An Offshore Generating Unit that is not an Offshore Synchronous Generating Unit including for the avoidance of doubt a Power Park Unit or Non-Synchronous Electricity Storage Unit located Offshore.</td>
</tr>
<tr>
<td>Offshore Platform</td>
<td>A single structure comprising of Plant and Apparatus located Offshore which includes one or more Offshore Grid Entry Points.</td>
</tr>
<tr>
<td>Offshore Power Park Module</td>
<td>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:</td>
</tr>
<tr>
<td></td>
<td>(a) connect to the same busbar which cannot be electrically split; or</td>
</tr>
<tr>
<td></td>
<td>(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.</td>
</tr>
<tr>
<td>Offshore Power Park String</td>
<td>A collection of Offshore Generating Units or Power Park Units or Non-Synchronous Electricity Storage Unit 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.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>------</td>
<td>------------</td>
</tr>
<tr>
<td>Offshore Synchronous Generating Unit</td>
<td>A Generating Unit or Synchronous Electricity Storage Unit located Offshore 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.</td>
</tr>
<tr>
<td>Offshore Synchronous Power Generating Module</td>
<td>A Synchronous Power Generating Module or Synchronous Electricity Storage Module located Offshore.</td>
</tr>
<tr>
<td>Offshore Tender Process</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Transmission Distribution Connection Agreement</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Transmission Licensee</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Transmission System</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Transmission System Development User Works or OTSDUW</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Transmission System User Assets or OTSUA</td>
<td>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.</td>
</tr>
<tr>
<td>Offshore Waters</td>
<td>Has the meaning given to “offshore waters” in Section 90(9) of the Energy Act 2004.</td>
</tr>
<tr>
<td>Offshore Works Assumptions</td>
<td>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.</td>
</tr>
<tr>
<td>Onshore</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Onshore DC Converter</strong></td>
<td>Any <strong>User Apparatus</strong> located <strong>Onshore</strong> with a <strong>Completion Date</strong> after 1st April 2005 used to convert alternating current electricity to direct current electricity, or vice versa. An <strong>Onshore DC Converter</strong> 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 <strong>Onshore DC Converter</strong> represents the bipolar configuration.</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td><strong>Onshore Generating Unit</strong></td>
<td>Unless otherwise provided in the Grid Code, any <strong>Apparatus</strong> located <strong>Onshore</strong> which produces electrical energy by converting or re-converting another source of energy, including, an <strong>Onshore Synchronous Generating Unit</strong> or <strong>Onshore Non-Synchronous Generating Unit</strong> which could also be part of a <strong>Power Generating Module</strong> or an <strong>Electricity Storage Module</strong>.</td>
</tr>
<tr>
<td><strong>Onshore Grid Entry Point</strong></td>
<td>A point at which a <strong>Onshore Generating Unit</strong> or a <strong>CCGT Module</strong> or a <strong>CCGT Unit</strong> or an <strong>Onshore Power Generating Module</strong> or an <strong>Onshore DC Converter</strong> or an <strong>Onshore HVDC Converter</strong> or an <strong>Onshore Power Park Module</strong> or an <strong>Onshore Electricity Storage Module</strong> or an <strong>External Interconnection</strong>, as the case may be, which is directly connected to the <strong>Onshore Transmission System</strong> connects to the <strong>Onshore Transmission System</strong>.</td>
</tr>
<tr>
<td><strong>Onshore HVDC Converter</strong></td>
<td>Any <strong>User Apparatus</strong> located <strong>Onshore</strong> used to convert alternating current electricity to direct current electricity, or vice versa. An <strong>Onshore HVDC Converter</strong> 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 <strong>Onshore HVDC Converter</strong> represents the bipolar configuration.</td>
</tr>
<tr>
<td><strong>Onshore Non-Synchronous Generating Unit</strong></td>
<td>A <strong>Generating Unit</strong> located <strong>Onshore</strong> that is not a <strong>Synchronous Generating Unit</strong> or <strong>Synchronous Electricity Storage Unit</strong> including for the avoidance of doubt a <strong>Power Park Unit</strong> or <strong>Non-Synchronous Electricity Storage Unit</strong> located <strong>Onshore</strong>.</td>
</tr>
<tr>
<td><strong>Onshore Power Park Module</strong></td>
<td>A collection of <strong>Non-Synchronous Generating Units</strong> that are powered by an <strong>Intermittent Power Source</strong> or connected through power electronic conversion technology or <strong>Non-Synchronous Electricity Storage Units</strong>, joined together by a <strong>System</strong> (registered as a <strong>Power Park Module</strong> under the <strong>PC</strong>) with a single electrical point of connection directly to the <strong>Onshore Transmission System</strong> (or <strong>User System if Embedded</strong>) with no intermediate <strong>Offshore Transmission System</strong> connections. The connection to the <strong>Onshore Transmission System</strong> (or <strong>User System if Embedded</strong>) may include a <strong>DC Converter</strong> or <strong>HVDC Converter</strong>.</td>
</tr>
<tr>
<td><strong>Onshore Synchronous Generating Unit</strong></td>
<td>An <strong>Onshore Generating Unit</strong> or <strong>Onshore Synchronous Electricity Storage Unit</strong> (which could also be part of an <strong>Onshore Power Generating Module</strong>) including, for the avoidance of doubt, a <strong>CCGT Unit</strong> or <strong>Synchronous Electricity Storage Unit</strong> in which, under all steady state conditions, the rotor rotates at a mechanical speed equal to the electrical frequency of the <strong>National Electricity Transmission System</strong> divided by the number of pole pairs of the <strong>Generating Unit</strong>.</td>
</tr>
<tr>
<td><strong>Onshore Synchronous Power Generating Module</strong></td>
<td>A Synchronous Power Generating Module or Synchronous Electricity Storage Module located Onshore.</td>
</tr>
<tr>
<td><strong>Onshore Transmission Licensee</strong></td>
<td>NGET, SPT, or SHETL.</td>
</tr>
<tr>
<td><strong>Onshore Transmission System</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>On-Site Generator Site</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Operating Code or OC</strong></td>
<td>That portion of the Grid Code which is identified as the Operating Code.</td>
</tr>
<tr>
<td><strong>Operating Margin</strong></td>
<td>Contingency Reserve plus Operating Reserve.</td>
</tr>
<tr>
<td><strong>Operating Reserve</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Operation</strong></td>
<td>A scheduled or planned action relating to the operation of a System (including an Embedded Power Station).</td>
</tr>
<tr>
<td><strong>Operational Data</strong></td>
<td>Data required under the Operating Codes and/or Balancing Codes.</td>
</tr>
<tr>
<td><strong>Operational Day</strong></td>
<td>The period from 0500 hours on one day to 0500 on the following day.</td>
</tr>
<tr>
<td><strong>Operation Diagrams</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Operational Effect</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Operational Intertripping</strong></td>
<td>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 Electricity Storage Module, System to DC Converter, System to Power Generating Module, System to HVDC Converter and System to Demand intertripping schemes.</td>
</tr>
<tr>
<td>Operational Notifications</td>
<td>Any Energisation Operational Notification, Interim Operational Notification, Final Operational Notification or Limited Operational Notification issued from The Company to a User.</td>
</tr>
<tr>
<td>----------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Operational Planning</td>
<td>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.</td>
</tr>
<tr>
<td>Operational Planning Margin</td>
<td>An operational planning margin set by The Company.</td>
</tr>
<tr>
<td>Operational Planning Phase</td>
<td>The period from 8 weeks to the end of the 5th year ahead of real time operation.</td>
</tr>
<tr>
<td>Operational Procedures</td>
<td>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.</td>
</tr>
<tr>
<td>Operational Switching</td>
<td>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.</td>
</tr>
<tr>
<td>Other Relevant Data</td>
<td>The data listed in BC1.4.2(f) under the heading Other Relevant Data.</td>
</tr>
<tr>
<td>OTSDUW Arrangements</td>
<td>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.</td>
</tr>
<tr>
<td>OTSDUW Data and Information</td>
<td>The data and information to be provided by Users undertaking OTSDUW, to The Company in accordance with Appendix F of the Planning Code.</td>
</tr>
<tr>
<td>OTSDUW DC Converter</td>
<td>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.</td>
</tr>
<tr>
<td>OTSDUW Development and Data Timetable</td>
<td>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.</td>
</tr>
<tr>
<td>OTSDUW Network Data and Information</td>
<td>The data and information to be provided by The Company to Users undertaking OTSDUW in accordance with Appendix F of the Planning Code.</td>
</tr>
<tr>
<td><strong>OTSDUW Plant and Apparatus</strong></td>
<td>Plant and Apparatus, including any OTSDUW DC Converter, designed by the User under the OTSDUW Arrangements.</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>OTSUA Transfer Time</strong></td>
<td>The time and date at which the OTSUA are transferred to a Relevant Transmission Licensee.</td>
</tr>
<tr>
<td><strong>Out of Synchronism</strong></td>
<td>The condition where a System or Generating Unit or Power Generating Module cannot meet the requirements to enable it to be Synchronised.</td>
</tr>
<tr>
<td><strong>Output Usable or OU</strong></td>
<td>The forecast value (in MW), profiled across the time period affected by the unplanned or planned Event of the 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.</td>
</tr>
<tr>
<td><strong>Over-excitation Limiter</strong></td>
<td>Shall have the meaning ascribed to that term in IEC 34-16-1:1991 [equivalent to British Standard BS4999 Section 116.1: 1992].</td>
</tr>
<tr>
<td><strong>Panel Chairperson</strong></td>
<td>A person appointed as such in accordance with GR.4.1.</td>
</tr>
<tr>
<td><strong>Panel Member</strong></td>
<td>Any of the persons identified as such in GR.4.</td>
</tr>
<tr>
<td><strong>Panel Members' Recommendation</strong></td>
<td>The recommendation in accordance with the &quot;Grid Code Review Panel Recommendation Vote&quot;.</td>
</tr>
<tr>
<td><strong>Panel Secretary</strong></td>
<td>A person appointed as such in accordance with GR.3.1.2(d).</td>
</tr>
<tr>
<td><strong>Part 1 System Ancillary Services</strong></td>
<td>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 or ECC.8.1 headed Part 1.</td>
</tr>
<tr>
<td><strong>Part 2 System Ancillary Services</strong></td>
<td>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 or ECC.8.1 headed Part 2.</td>
</tr>
<tr>
<td><strong>Part Load</strong></td>
<td>The condition of a Genset, or Cascade Hydro Scheme which is Loaded but is not running at its Maximum Export Limit.</td>
</tr>
</tbody>
</table>
| **Peak Current Rating**       | For a GBGF-I this is the larger of either the: -  
|                               | • The registered maximum steady-state current plus the maximum additional current to supply the Active ROCOF Response Power plus the Defined Active Damping Power; or.  
|                               | • The registered maximum steady-state current plus the maximum additional current to supply the Phase Jump Angle limit power, or.  
|                               | This is the maximum short term total current as declared by the Grid Forming Plant Owner in accordance with PC.A.5.8.1. |
| 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. |
<p>| Partial Shutdown | The same as a <strong>Total Shutdown</strong> except that all generation has ceased in a separate part of the <strong>Total System</strong> and there is no electricity supply from <strong>External Interconnections</strong> or other parts of the <strong>Total System</strong> to that part of the <strong>Total System</strong> and, therefore, that part of the <strong>Total System</strong> is shutdown, with the result that it is not possible for that part of the <strong>Total System</strong> to begin to function again without <strong>The Company</strong>’s directions relating to a <strong>Black Start</strong>. |
| Pending Grid Code Modification Proposal | A <strong>Grid Code Modification Proposal</strong> in respect of which, at the relevant time, the <strong>Authority</strong> has not yet made a decision as to whether to direct such <strong>Grid Code Modification Proposal</strong> to be made pursuant to the <strong>Transmission Licence</strong> (whether or not a <strong>Grid Code Modification Report</strong> has been submitted in respect of such <strong>Grid Code Modification Proposal</strong>) or, in the case of a <strong>Grid Code Self Governance Proposals</strong>, in respect of which the <strong>Grid Code Review Panel</strong> has not yet voted whether or not to approve. |
| Phase Jump Angle | The difference in the measured phase angle of the voltage at the <strong>Grid Entry Point</strong> or <strong>User System Entry Point</strong> in a given mains half cycle compared with the measured phase angle of the voltage at the <strong>Grid Entry Point</strong> or <strong>User System Entry Point</strong> in the previous mains half cycle. |
| Phase Jump Angle Limit | The maximum <strong>Phase Jump Angle</strong> when applied to a <strong>GBGF-I</strong> which will result in a linear controlled response without activating current limiting functions. This is specified for a <strong>System</strong> angle near to zero which will be considered to be the normal operating angle under steady state conditions. |
| Phase Jump Angle Withstand | The maximum <strong>Phase Jump Angle</strong> change when applied to a <strong>GBGF-I</strong> which will result in the <strong>GBGF-I</strong> remaining in stable operation with current limiting functions activated. This is specified for a <strong>System</strong> angle near to zero which will be considered to be the normal operating angle under steady state conditions. |
| Phase (Voltage) Unbalance | The ratio (in percent) between the rms values of the negative sequence component and the positive sequence component of the voltage. |</p>
<table>
<thead>
<tr>
<th><strong>Physical Notification</strong></th>
<th>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.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Planning Code or PC</strong></td>
<td>That portion of the Grid Code which is identified as the Planning Code.</td>
</tr>
<tr>
<td><strong>Planned Maintenance Outage</strong></td>
<td>An outage of The Company’s electronic data communication facilities as provided for in CC.6.5.8 or ECC.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.</td>
</tr>
<tr>
<td><strong>Planned Outage</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Plant</strong></td>
<td>Fixed and movable items used in the generation and/or supply and/or transmission of electricity, other than Apparatus.</td>
</tr>
<tr>
<td><strong>Point of Common Coupling</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Point of Connection</strong></td>
<td>An electrical point of connection between the National Electricity Transmission System and a User’s System.</td>
</tr>
<tr>
<td><strong>Point of Isolation</strong></td>
<td>The point on Apparatus (as defined in OC8A.1.6.2 and OC8B.1.7.2) at which Isolation is achieved.</td>
</tr>
<tr>
<td><strong>Post-Control Phase</strong></td>
<td>The period following real time operation.</td>
</tr>
<tr>
<td><strong>Power Available</strong></td>
<td>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 electrical or mechanical or meteorological data (including wind speed) 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 unit that is not generating or supplying power 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.</td>
</tr>
<tr>
<td><strong>Power Factor</strong></td>
<td>The ratio of Active Power to Apparent Power.</td>
</tr>
<tr>
<td><strong>Power-Generating Module</strong></td>
<td>Either a <strong>Synchronous Power Generating Module</strong>, a <strong>Synchronous Electricity Storage Module</strong>, a <strong>Power Park Module</strong> or a <strong>Non-Synchronous Electricity Storage Module</strong> owned or operated by an <strong>EU Generator</strong>.</td>
</tr>
<tr>
<td>-----------------------------</td>
<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Power-Generating Module Document (PGMD)</strong></td>
<td>A document provided by the <strong>Generator</strong> to <strong>The Company</strong> for a <strong>Type B</strong> or <strong>Type C Power Generating Module</strong> which confirms that the <strong>Power Generating Module</strong>'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.</td>
</tr>
<tr>
<td><strong>Power Generating Module Performance Chart</strong></td>
<td>A diagram showing the <strong>Active Power</strong> (MW) and <strong>Reactive Power</strong> (MVAr) capability limits within which a <strong>Synchronous Power Generating Module</strong> or <strong>Power Park Module</strong> at its <strong>Grid Entry Point</strong> or <strong>User System Entry Point</strong> will be expected to operate under steady state conditions.</td>
</tr>
<tr>
<td><strong>Power Island</strong></td>
<td><strong>Gensets</strong> at an isolated <strong>Power Station</strong>, together with complementary local <strong>Demand</strong>. In Scotland a <strong>Power Island</strong> may include more than one <strong>Power Station</strong>.</td>
</tr>
<tr>
<td><strong>Power Park Module</strong></td>
<td>Any <strong>Onshore Power Park Module</strong> or <strong>Offshore Power Park Module</strong>.</td>
</tr>
<tr>
<td><strong>Power Park Module Availability Matrix</strong></td>
<td>The matrix described in Appendix 1 to BC1 under the heading <strong>Power Park Module Availability Matrix</strong>.</td>
</tr>
<tr>
<td><strong>Power Park Module Planning Matrix</strong></td>
<td>A matrix in the form set out in Appendix 4 of OC2 showing the combination of <strong>Power Park Units</strong> within a <strong>Power Park Module</strong> which would be expected to be running under normal conditions.</td>
</tr>
<tr>
<td><strong>Power Park Unit</strong></td>
<td>A <strong>Generating Unit</strong> within a <strong>Power Park Module</strong>.</td>
</tr>
<tr>
<td><strong>Power Station</strong></td>
<td>An installation comprising one or more <strong>Generating Units</strong> or <strong>Power Park Modules</strong> or <strong>Power Generating Modules</strong> or <strong>Electricity Storage Modules</strong> (even where sited separately) owned and/or controlled by the same <strong>Generator</strong>, which may reasonably be considered as being managed as one <strong>Power Station</strong>.</td>
</tr>
<tr>
<td><strong>Power System Stabiliser or PSS</strong></td>
<td>Equipment controlling the <strong>Exciter</strong> 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).</td>
</tr>
<tr>
<td><strong>Preface</strong></td>
<td>The preface to the Grid Code (which does not form part of the Grid Code and therefore is not binding).</td>
</tr>
<tr>
<td><strong>Preliminary Notice</strong></td>
<td>A notice in writing, sent by <strong>The Company</strong> both to all <strong>Users</strong> identified by it under OC12.4.2.1 and to the <strong>Test Proposer</strong>, notifying them of a proposed <strong>System Test</strong>.</td>
</tr>
<tr>
<td><strong>Preliminary Project Planning Data</strong></td>
<td>Data relating to a proposed <strong>User Development</strong> at the time the <strong>User</strong> applies for a <strong>CUSC Contract</strong> but before an offer is made and accepted.</td>
</tr>
</tbody>
</table>
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 (ii) a **Fixed Proposed Implementation Date**.

Proposer

In relation to a particular **Grid Code Modification Proposal**, the person who makes such **Grid Code Modification Proposal**.

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.

Pumped Storage

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 Generating Unit** | A Generating Unit at a **Pumped Storage Plant** |
| **Pumped Storage Generator** | A Generator which owns and/or operates any **Pumped Storage Plant**. |
| **Pumped Storage Plant** | A Power Station comprising **Pumped Storage Generating Units**. |
| **Pumped Storage Unit** | A Generating Unit within a **Pumped Storage Plant**. For the avoidance of doubt, a **Pumped Storage Unit** is not considered to form part of an **Electricity Storage Unit** unless specifically declared by the Generator. |
| **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** = \( \cos[\arctan\left(\frac{q}{P_{\text{max}}}\right)] \) |
|  | 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 BS4999 Section 116.1: 1992**]. |
| **Rated MW** | The “rating-plate” MW output of a Power Generating Module, Generating Unit, Power Park Module, Electricity Storage 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.

(d) in an importing mode, is that input up to which an Electricity Storage Module was designed to operate being the maximum continuous electric input which the Electricity Storage Module was designed to achieve under normal operating conditions. In an exporting mode is:-

(i) that output up to which the Synchronous Electricity Storage Unit was designed to operate (Calculated as specified in British Standard BS EN 60034 – 1: 1995); or

(ii) the nominal rating for the MW output of a Non-Synchronous Electricity Storage Module being the maximum continuous electric output power which the Non-Synchronous Electricity Storage Module was designed to achieve under normal operating conditions. |

| **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 Despatch to Zero Mvar Network Restriction** | A Reactive Despatch Network Restriction which prevents an Embedded Power Generating Module, an Embedded Generating Unit, Embedded Power Park Module, Embedded HVDC System, HVDC Converter at an Embedded HVDC Converter Station or DC Converter at an Embedded DC Converter Station from supplying power at zero MVAR at all Active Power output levels up to and including Rated MW at the Grid Entry Point (or User System Entry Point if Embedded). |

| **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. |
| Regenerative Braking | A method of braking in which energy is extracted from the parts braked, which may be returned directly to the System and the purpose of the braking is motion control. |
### Registered Capacity

<p>| (a) | In the case of a <strong>Generating Unit</strong> other than that forming part of a <strong>CCGT Module</strong> or <strong>Power Park Module</strong> or <strong>Power Generating Module</strong>, the normal full load capacity of a <strong>Generating Unit</strong> as declared by the <strong>Generator</strong>, less the MW consumed by the <strong>Generating Unit</strong> through the <strong>Generating Unit’s Unit Transformer</strong> 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 <strong>CCGT Module</strong> or <strong>Power Park Module</strong> owned or operated by a <strong>GB Generator</strong>, the normal full load capacity of the <strong>CCGT Module</strong> or <strong>Power Park Module</strong> (as the case may be) as declared by the <strong>GB Generator</strong>, being the <strong>Active Power</strong> declared by the <strong>GB Generator</strong> as being deliverable by the <strong>CCGT Module</strong> or <strong>Power Park Module</strong> at the <strong>Grid Entry Point</strong> (or in the case of an <strong>Embedded CCGT Module</strong> or <strong>Power Park Module</strong>, at the <strong>User System Entry Point</strong>), expressed in whole MW, or in MW to one decimal place. For the avoidance of doubt <strong>Maximum Capacity</strong> would apply to <strong>Power Generating Modules</strong> which form part of a <strong>Large, Medium or Small Power Station</strong>. |
| (c) | In the case of a <strong>Power Station</strong>, the maximum amount of <strong>Active Power</strong> deliverable by the <strong>Power Station</strong> at the <strong>Grid Entry Point</strong> (or in the case of an <strong>Embedded Power Station</strong> at the <strong>User System Entry Point</strong>), as declared by the <strong>Generator</strong>, expressed in whole MW, or in MW to one decimal place. The maximum <strong>Active Power</strong> deliverable is the maximum amount deliverable simultaneously by the <strong>Power Generating Modules</strong> and/or <strong>Generating Units</strong> and/or <strong>CCGT Modules</strong> and/or <strong>Power Park Modules</strong> less the MW consumed by the <strong>Power Generating Modules</strong> and/or <strong>Generating Units</strong> and/or <strong>CCGT Modules</strong> in producing that <strong>Active Power</strong> and forming part of a <strong>Power Station</strong>. |
| (d) | In the case of a <strong>DC Converter</strong> at a <strong>DC Converter Station</strong> or <strong>HVDC Converter</strong> at an <strong>HVDC Converter Station</strong>, the normal full load amount of <strong>Active Power</strong> transferable from a <strong>DC Converter</strong> or <strong>HVDC Converter</strong> at the <strong>Onshore Grid Entry Point</strong> (or in the case of an <strong>Embedded DC Converter Station</strong> or an <strong>Embedded HVDC Converter Station</strong> at the <strong>User System Entry Point</strong>), as declared by the <strong>DC Converter Station owner</strong> or <strong>HVDC System Owner</strong>, expressed in whole MW, or in MW to one decimal place. |
| (e) | In the case of a <strong>DC Converter Station</strong> or <strong>HVDC Converter Station</strong>, the maximum amount of <strong>Active Power</strong> transferable from a <strong>DC Converter Station</strong> or <strong>HVDC Converter Station</strong> at the <strong>Onshore Grid Entry Point</strong> (or in the case of an <strong>Embedded DC Converter Station</strong> or <strong>Embedded HVDC Converter Station</strong> at the <strong>User System Entry Point</strong>), as declared by the <strong>DC Converter Station owner</strong> or <strong>HVDC System Owner</strong>, expressed in whole MW, or in MW to one decimal place. |
| (f) | In the case of an <strong>Electricity Storage Module</strong>, the normal full load amount of <strong>Active Power</strong> transferable from an <strong>Electricity Storage Module</strong> at the <strong>Grid Entry Point</strong> (or in the case of an <strong>Embedded Electricity Storage Module</strong> at the <strong>User System Entry Point</strong>), as declared by the <strong>Generator</strong>, expressed in whole MW, or in MW to one decimal place. |</p>
<table>
<thead>
<tr>
<th>Registered Data</th>
<th>Those items of <strong>Standard Planning Data</strong> and <strong>Detailed Planning Data</strong> which upon connection become fixed (subject to any subsequent changes).</th>
</tr>
</thead>
</table>
| 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.  
In the case of an **Electricity Storage Module**, the maximum amount of **Active Power** transferable into an **Electricity Storage Module** at the **Grid Entry Point** (or in the case of an **Embedded Electricity Storage Module** at the **User System Entry Point**), as declared by the **Generator**, expressed in whole MW. |
<p>| Regulations | The Utilities Contracts Regulations 1996, as amended from time to time. |
| Regulated Sections | Parts of the Grid Code that are referenced in <strong>Governance Rules</strong> Annex GR.B as amended from time to time with the approval of the <strong>Authority</strong>. |
| Reheater Time Constant | Determined at <strong>Registered Capacity</strong>, the reheater time constant will be construed in accordance with the principles of the IEEE Committee Report &quot;Dynamic Models for Steam and Hydro Turbines in Power System Studies&quot; published in 1973 which apply to such phrase. |
| Rejected Grid Code Modification Proposal | A <strong>Grid Code Modification Proposal</strong> in respect of which the <strong>Authority</strong> has decided not to direct <strong>The Company</strong> to modify the <strong>Grid Code</strong> pursuant to <strong>The Company’s Transmission Licence</strong> in the manner set out herein or, in the case of a <strong>Grid Code Self Governance Proposals</strong>, in respect of which the <strong>Grid Code Review Panel</strong> has voted not to approve. |
| Related Person | Means, in relation to an individual, any member of their immediate family, their employer (and any former employer of theirs within the previous 12 months), any partner with whom they are in partnership, and any company or <strong>Affiliate</strong> of a company in which they or any member of their immediate family controls more than 20% of the voting rights in respect of the shares of the company; |
| Relevant E&amp;W Transmission Licensee | As the context requires <strong>NGET</strong> and/or an <strong>E&amp;W Offshore Transmission Licensee</strong>. |
| Relevant Party | Has the meaning given in GR15.10(a). |</p>
<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relevant Scottish Transmission Licensee</td>
<td>As the context requires SPT and/or SHETL and/or a Scottish Offshore Transmission Licensee.</td>
</tr>
<tr>
<td>Relevant Transmission Licensee</td>
<td>Means National Grid Electricity Transmission plc (NGET) in its Transmission Area or SP Transmission plc (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.</td>
</tr>
<tr>
<td>Relevant Unit</td>
<td>As defined in the STC, Schedule 3.</td>
</tr>
<tr>
<td>Remote End HVDC Converter Station</td>
<td>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.</td>
</tr>
<tr>
<td>Remote Transmission Assets</td>
<td>Any Plant and Apparatus or meters owned by NGET which:</td>
</tr>
<tr>
<td></td>
<td>(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</td>
</tr>
<tr>
<td></td>
<td>(b) are by agreement between NGET and such User operated under the direction and control of such User.</td>
</tr>
<tr>
<td>Replacement Reserves (RR)</td>
<td>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;</td>
</tr>
<tr>
<td>Responsible Engineer/Operator</td>
<td>A person nominated by a User to be responsible for System control.</td>
</tr>
<tr>
<td>Responsible Manager</td>
<td>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.</td>
</tr>
<tr>
<td>Restoration Service Provider</td>
<td>A Black Start Service Provider or User with a legal or contractual obligation to provide a service contributing to one or several measures of the System Restoration Plan.</td>
</tr>
<tr>
<td>Re-synchronisation</td>
<td>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.</td>
</tr>
<tr>
<td>RR Acceptance</td>
<td>The results of the TERRE auction for each BM Participant.</td>
</tr>
<tr>
<td>Restricted</td>
<td>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.</td>
</tr>
<tr>
<td>ROCOF</td>
<td>Rate of Change of Frequency</td>
</tr>
<tr>
<td><strong>RR Instruction</strong></td>
<td><strong>Replacement Reserve</strong> Instruction – used for instructing BM Participants after the results of the TERRE auction. An <strong>RR Instruction</strong> has the same format as a Bid-Offer Acceptance but has type field indicating it is for <strong>TERRE</strong>.</td>
</tr>
<tr>
<td>-------------------</td>
<td>-------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Safety Co-ordinator</strong></td>
<td>A person or persons nominated by a Relevant E&amp;W Transmission Licensee and each E&amp;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&amp;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.</td>
</tr>
<tr>
<td><strong>Safety From The System</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Safety Key</strong></td>
<td>A key unique at the Location capable of operating a lock which will cause an Isolating Device and/or Earthing Device to be Locked.</td>
</tr>
<tr>
<td><strong>Safety Log</strong></td>
<td>A chronological record of messages relating to safety co-ordination sent and received by each Safety Co-ordinator under OC8.</td>
</tr>
<tr>
<td><strong>Safety Precautions</strong></td>
<td>Isolation and/or Earthing.</td>
</tr>
<tr>
<td><strong>Safety Rules</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Scottish Offshore Transmission System</strong></td>
<td>An Offshore Transmission System with an Interface Point in Scotland.</td>
</tr>
<tr>
<td><strong>Scottish Offshore Transmission Licensee</strong></td>
<td>A person who owns or operates a Scottish Offshore Transmission System pursuant to a Transmission Licence.</td>
</tr>
<tr>
<td><strong>Scottish Transmission System</strong></td>
<td>Collectively SPT’s Transmission System and SHETL’s Transmission System and any Scottish Offshore Transmission Systems.</td>
</tr>
<tr>
<td><strong>Scottish User</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Secondary BM Unit</strong></td>
<td>Has the same meaning set out in the BSC.</td>
</tr>
<tr>
<td><strong>Secondary Response</strong></td>
<td>The automatic increase in <strong>Active Power</strong> output of a <strong>Genset</strong> or, as the case may be, the decrease in <strong>Active Power Demand</strong> in response to a <strong>System Frequency</strong> fall. This increase in <strong>Active Power</strong> output or, as the case may be, the decrease in <strong>Active Power Demand</strong> must be in accordance with the provisions of the relevant <strong>Ancillary Services Agreement</strong> which will provide that it will be fully available by 30 seconds from the time of the start of the <strong>Frequency</strong> fall and be sustainable for at least a further 30 minutes. The interpretation of the <strong>Secondary Response</strong> to a -0.5 Hz frequency change is shown diagrammatically in Figure CC.A.3.2 or Figure ECC.A.3.2.</td>
</tr>
<tr>
<td>------------------------</td>
<td>-------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Secretary of State</strong></td>
<td>Has the same meaning as in the <strong>Act</strong>.</td>
</tr>
<tr>
<td><strong>Secured Event</strong></td>
<td>Has the meaning set out in the <strong>Security and Quality of Supply Standard</strong>.</td>
</tr>
<tr>
<td><strong>Security and Quality of Supply Standard (SQSS)</strong></td>
<td>The version of the document entitled ‘Security and Quality of Supply Standard’ established pursuant to the <strong>Transmission Licence</strong> in force at the time of entering into the relevant <strong>Bilateral Agreement</strong>.</td>
</tr>
<tr>
<td><strong>Self-Governance Criteria</strong></td>
<td>A proposed <strong>Modification</strong> that, if implemented, (a) is unlikely to have a material effect on: (i) existing or future electricity consumers; and (ii) competition in the generation, storage, distribution, or supply of electricity or any commercial activities connected with the generation, storage, distribution or supply of electricity; and (iii) the operation of the <strong>National Electricity Transmission System</strong>; and (iv) matters relating to sustainable development, safety or security of supply, or the management of market or network emergencies; and (v) the <strong>Grid Code</strong>’s governance procedures or the <strong>Grid Code</strong>’s modification procedures, and (b) is unlikely to discriminate between different classes of Users. (c) other than where the modification meets the <strong>Fast Track Criteria</strong>, will not constitute an amendment to the <strong>Regulated Sections</strong> of the <strong>Grid Code</strong>.</td>
</tr>
<tr>
<td><strong>Self-Governance Modifications</strong></td>
<td>A <strong>Grid Code Modification Proposal</strong> that does not fall within the scope of a <strong>Significant Code Review</strong> and that meets the <strong>Self-Governance Criteria</strong> or which the <strong>Authority</strong> directs is to be treated as such any direction under GR.24.4.</td>
</tr>
<tr>
<td><strong>Self-Governance Statement</strong></td>
<td>The statement made by the <strong>Grid Code Review Panel</strong> and submitted to the <strong>Authority</strong>: (a) confirming that, in its opinion, the <strong>Self-Governance Criteria</strong> are met and the proposed <strong>Grid Code Modification Proposal</strong> is suitable for the Self-Governance route; and (b) providing a detailed explanation of the <strong>Grid Code Review Panel</strong>’s reasons for that opinion.</td>
</tr>
<tr>
<td>Term</td>
<td>Definition</td>
</tr>
<tr>
<td>------</td>
<td>------------</td>
</tr>
<tr>
<td><strong>Setpoint Voltage</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Settlement Period</strong></td>
<td>A period of 30 minutes ending on the hour and half-hour in each hour during a day.</td>
</tr>
<tr>
<td><strong>Seven Year Statement</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>SF₆ Gas Zone</strong></td>
<td>A segregated zone surrounding electrical conductors within a casing containing SF₆ gas.</td>
</tr>
<tr>
<td><strong>SHETL</strong></td>
<td>Scottish Hydro-Electric Transmission Limited.</td>
</tr>
<tr>
<td><strong>Shutdown</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Significant Code Review</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Significant Code Review Phase</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Significant Event</strong></td>
<td>An Event, as defined in OC3.4.1.</td>
</tr>
<tr>
<td><strong>Significant Incident</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Simultaneous Tap Change</strong></td>
<td>A tap change implemented on the generator step-up transformers of <strong>Synchronised Gensets</strong>, effected by <strong>Generators</strong> in response to an instruction from <strong>The Company</strong> issued simultaneously to the relevant <strong>Power Stations</strong>. The instruction, preceded by advance notice, must be effected as soon as possible, and in any event within one minute of receipt from <strong>The Company</strong> of the instruction.</td>
</tr>
<tr>
<td><strong>Single Intraday Coupling</strong></td>
<td>The continuous process where collected orders are matched and cross-zonal capacity is allocated simultaneously for different bidding zones in the intraday market.</td>
</tr>
<tr>
<td><strong>Single Line Diagram</strong></td>
<td>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 <strong>Large Power Stations</strong> are connected, and the points at which <strong>Demand</strong> is supplied.</td>
</tr>
<tr>
<td><strong>Single Point of Connection</strong></td>
<td>A single <strong>Point of Connection</strong>, with no interconnection through the <strong>User’s System</strong> to another <strong>Point of Connection</strong>.</td>
</tr>
<tr>
<td><strong>Site Common Drawings</strong></td>
<td>Drawings prepared for each <strong>Connection Site</strong> (and in the case of <strong>OTSDUW, Transmission Interface Site</strong>) which incorporate <strong>Connection Site</strong> (and in the case of <strong>OTSDUW, Transmission Interface Site</strong>) layout drawings, electrical layout drawings, common protection/ control drawings and common services drawings.</td>
</tr>
<tr>
<td><strong>Site Responsibility Schedule</strong></td>
<td>A schedule containing the information and prepared on the basis of the provisions set out in Appendix 1 of the <strong>CC</strong> and Appendix E1 of the <strong>ECC</strong>.</td>
</tr>
<tr>
<td><strong>Slope</strong></td>
<td>The ratio of the steady state change in voltage, as a percentage of the nominal voltage, to the steady state change in <strong>Reactive Power</strong> output, in per unit of <strong>Reactive Power</strong> capability. For the avoidance of doubt, the value indicates the percentage voltage reduction that will result in a 1 per unit increase in <strong>Reactive Power</strong> generation.</td>
</tr>
<tr>
<td><strong>Small Participant</strong></td>
<td>Has the meaning given in the <strong>CUSC</strong>.</td>
</tr>
</tbody>
</table>
**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 plc

**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. A **Grid Code Modification Proposal** that constitutes an amendment to the **Regulated Sections** of the Grid Code shall be a **Standard Modification** except where it is an **Urgent Modification** or where it meets the **Fast Track Criteria**.

### 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 **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.
Storage User

A Generator who owns or operates one or more Electricity Storage Modules. For the avoidance of doubt:


(b) the European Connection Conditions (ECC’s) shall apply to Storage Users on the basis set out in Paragraph ECC1.1(d).

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 equal to the total Output Usable:

(a) minus the forecast of Active Power Demand, and
(b) minus the Operational Planning Margin.

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 reconvert 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.
<table>
<thead>
<tr>
<th><strong>Synchronous Electricity Storage Unit</strong></th>
<th>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.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Synchronising Generation</strong></td>
<td>The amount of MW (in whole MW) produced at the moment of synchronising.</td>
</tr>
<tr>
<td><strong>Synchronising Group</strong></td>
<td>A group of two or more Gensets which require a minimum time interval between their Synchronising or De-Synchronising times.</td>
</tr>
<tr>
<td><strong>Synchronous Area</strong></td>
<td>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;</td>
</tr>
<tr>
<td><strong>Synchronous Compensation</strong></td>
<td>The operation of rotating synchronous Apparatus for the specific purpose of either the generation or absorption of Reactive Power.</td>
</tr>
<tr>
<td><strong>Synchronous Compensation Equipment</strong></td>
<td>Apparatus which has the function of providing Synchronous Compensation. For the avoidance of doubt, one or more Synchronous Compensation units would not constitute an Electricity Storage Module unless it could be operated in a controllable manner.</td>
</tr>
<tr>
<td><strong>Synchronous Electricity Storage Module</strong></td>
<td>A Synchronous Power Generating Module which can convert and reconvert 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.</td>
</tr>
<tr>
<td><strong>Synchronous Electricity Storage Unit</strong></td>
<td>A Synchronous Generating Unit which can supply and 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.</td>
</tr>
<tr>
<td><strong>Synchronous Flywheel</strong></td>
<td>An item of synchronously rotating Plant for the specific purpose of contributing inertia to the System. One or more Synchronous Flywheels would not be considered to form an Electricity Storage Module unless it could be operated in a controllable manner for its AC input and output power.</td>
</tr>
<tr>
<td><strong>Synchronous Generating Unit</strong></td>
<td>Any Onshore Synchronous Generating Unit or Offshore Synchronous Generating Unit.</td>
</tr>
<tr>
<td><strong>Synchronous Generating Unit Performance Chart</strong></td>
<td>A diagram showing the Active 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.</td>
</tr>
<tr>
<td><strong>Synchronous Power-Generating Module</strong></td>
<td>An indivisible set of installations which can convert or re-convert electrical energy from another source of energy such that the frequency of the supplied 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 <strong>Synchronous Power Generating Module</strong> could comprise of one or more <strong>Synchronous Generating Units</strong> or one or more <strong>Synchronous Electricity Storage Units</strong>.</td>
</tr>
<tr>
<td><strong>Synchronous Power Generating Module Matrix</strong></td>
<td>The matrix described in Appendix 1 to BC1 under the heading <strong>Synchronous Power Generating Module Matrix</strong>.</td>
</tr>
<tr>
<td><strong>Synchronous Power Generating Module Planning Matrix</strong></td>
<td>A matrix in the form set out in Appendix 5 of OC2 showing the combination of <strong>Synchronous Generating Units</strong> within a <strong>Synchronous Power Generating Module</strong> which would be running in relation to any given MW output.</td>
</tr>
<tr>
<td><strong>Synchronous Power Generating Unit</strong></td>
<td>Has the same meaning as a <strong>Synchronous Generating Unit</strong> and would be considered to be part of a <strong>Power Generating Module</strong>.</td>
</tr>
<tr>
<td><strong>Synchronous Speed</strong></td>
<td>That speed required by a <strong>Generating Unit</strong> to enable it to be <strong>Synchronised</strong> to a <strong>System</strong>.</td>
</tr>
<tr>
<td><strong>System</strong></td>
<td>Any <strong>User System</strong> and/or the <strong>National Electricity Transmission System</strong>, as the case may be.</td>
</tr>
<tr>
<td><strong>System Ancillary Services</strong></td>
<td>Collectively <strong>Part 1 System Ancillary Services</strong> and <strong>Part 2 System Ancillary Services</strong>.</td>
</tr>
<tr>
<td><strong>System Constraint</strong></td>
<td>A limitation on the use of a <strong>System</strong> due to lack of transmission capacity or other <strong>System</strong> conditions.</td>
</tr>
<tr>
<td><strong>System Constrained Capacity</strong></td>
<td>That portion of <strong>Registered Capacity</strong> or <strong>Registered Import Capacity</strong> not available due to a <strong>System Constraint</strong>.</td>
</tr>
<tr>
<td><strong>System Constraint Group</strong></td>
<td>A part of the <strong>National Electricity Transmission System</strong> which, because of <strong>System Constraints</strong>, is subject to limits of <strong>Active Power</strong> which can flow into or out of (as the case may be) that part.</td>
</tr>
<tr>
<td><strong>System Defence Plan</strong></td>
<td>A document prepared by <strong>The Company</strong>, as published on its <strong>Website</strong>, outlining how the requirements of the “defence plan”, as provided for by <strong>Retained EU Law</strong> (Commission Regulation (EU) 2017/2196), has been implemented within the <strong>GB Synchronous Area</strong>.</td>
</tr>
</tbody>
</table>
| **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: 

\[
Dp = 1 - \frac{F_1}{A}
\]

Where:

\[
A = \text{Total number of System faults}
\]

\[
F_1 = \text{Number of System faults where there was a failure to trip a circuit-breaker.}
\] |
| **System Incidents Report** | A report submitted to the GCRP on a monthly basis, containing, but not limited to, a list of **Significant Events**, as detailed in OC3.4.1. |
| **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. |
<p>| <strong>System Negative Reserve Active Power Margin or System NRAPM</strong> | That margin of Active Power sufficient to allow the largest loss of Load at any time. |
| <strong>System Operator - Transmission Owner Code or STC</strong> | Has the meaning set out in The Company’s Transmission Licence |
| <strong>System Restoration Plan</strong> | A document prepared by The Company, as published on its Website, outlining how the requirements of the “restoration plan”, as defined in Retained EU Law (Commission Regulation (EU) 2017/2196), has been implemented within the GB Synchronous Area. |
| <strong>System Telephony</strong> | 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. |
| <strong>System Tests</strong> | 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. |
| <strong>System to Demand Intertrip Scheme</strong> | An intertrip scheme which disconnects Demand when a System fault has arisen to prevent abnormal conditions occurring on the System. |
| <strong>System to Generator Operational Intertripping</strong> | 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). |
| <strong>System to Generator Operational Intertripping Scheme</strong> | A System to Generating Unit or System to CCGT Module or System to Power Park Module or System to Power Generating Module or System to Electricity Storage 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 Category 4 Intertripping Scheme. |</p>
<table>
<thead>
<tr>
<th>Target Frequency</th>
<th>That <strong>Frequency</strong> determined by The Company, in its reasonable opinion, as the desired operating <strong>Frequency</strong> of the <strong>Total System</strong>. 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 <strong>System</strong> during disputes affecting fuel supplies.</th>
</tr>
</thead>
</table>
| 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. |
<p>| TERRE | <strong>Trans European Replacement Reserves Exchange</strong> – a market covering the procurement of replacement reserves across Europe. |
| 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 <strong>TERRE Activation Periods</strong> in one <strong>TERRE Auction Period</strong>. |
| 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 <strong>TERRE Auction Periods</strong> in a day. |
| TERRE Bid | A submission by a <strong>BM Participant</strong> covering the price and MW deviation offered into the <strong>TERRE</strong> auction (please note – in the <strong>Balancing Mechanism</strong> the term bid has a different meaning – in this case a bid can be an upward or downward MW change). |
| TERRE Central Platform | An <strong>IT system</strong> which implements the <strong>TERRE</strong> auction. |
| TERRE Data Validation and Consistency Rules | A document produced by the central <strong>TERRE</strong> project detailing the correct format of submissions for <strong>TERRE</strong>. |
| TERRE Gate Closure | 60 minutes before the start of the <strong>TERRE Auction Period</strong> (note still ongoing discussions if this may become 55 minutes). |
| TERRE Instruction Guide | Details specific rules for creating an <strong>RR Instruction</strong> from an <strong>RR Acceptance</strong>. |
| Test Co-ordinator | A person who co-ordinates <strong>System Tests</strong>. |
| Test Panel | A panel, whose composition is detailed in <strong>OC12</strong>, which is responsible, inter alia, for considering a proposed <strong>System Test</strong>, and submitting a <strong>Proposal Report</strong> and a <strong>Test Programme</strong>. |
| Test Programme | A programme submitted by the <strong>Test Panel</strong> to <strong>The Company</strong>, the <strong>Test Proposer</strong>, and each <strong>User</strong> identified by <strong>The Company</strong> 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 <strong>System Test</strong> (including those responsible for the site safety) and such other matters as the <strong>Test Panel</strong> deems appropriate. |
| Test Proposer | The person who submits a <strong>Proposal Notice</strong>. |</p>
<table>
<thead>
<tr>
<th><strong>Test Signal</strong></th>
<th>A signal in the form of a sine wave, applied to a GBGF-I to demonstrate its ability to contribute to Active Damping Power.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>The Company</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>The Company Control Engineer</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>The Company Operational Strategy</strong></td>
<td>The Company’s operational procedures which form the guidelines for operation of the National Electricity Transmission System.</td>
</tr>
<tr>
<td><strong>Total Shutdown</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Trading Point</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Transfer Date</strong></td>
<td>Such date as may be appointed by the Secretary of State by order under section 65 of the Act.</td>
</tr>
<tr>
<td><strong>Transmission</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Transmission Area</strong></td>
<td>Has the meaning set out in the Transmission Licence of a Transmission Licensee.</td>
</tr>
<tr>
<td><strong>Transmission Connected Demand Facilities</strong></td>
<td>A Demand Facility which has a Grid Supply Point to the National Electricity Transmission System.</td>
</tr>
<tr>
<td><strong>Transmission DC Converter</strong></td>
<td>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.</td>
</tr>
<tr>
<td><strong>Transmission Entry Capacity</strong></td>
<td>Has the meaning set out in the CUSC.</td>
</tr>
<tr>
<td>Transmission Interface Circuit</td>
<td>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.</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>Transmission Interface Point</td>
<td>Means the electrical point of connection between the Offshore Transmission System and an Onshore Transmission System.</td>
</tr>
<tr>
<td>Transmission Interface Site</td>
<td>The site at which the Transmission Interface Point is located.</td>
</tr>
<tr>
<td>Transmission Licence</td>
<td>A licence granted under Section 6(1)(b) of the Act.</td>
</tr>
<tr>
<td>Transmission Licensee</td>
<td>The Company and any Onshore Transmission Licensee or Offshore Transmission Licensee.</td>
</tr>
<tr>
<td>Transmission Site</td>
<td>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.</td>
</tr>
<tr>
<td>Transmission System</td>
<td>Has the same meaning as the term &quot;licensee's transmission system&quot; in the Transmission Licence of a Transmission Licensee.</td>
</tr>
<tr>
<td>Turbine Time Constant</td>
<td>Determined at Registered Capacity, the turbine time constant will be construed in accordance with the principles of the IEEE Committee Report &quot;Dynamic Models for Steam and Hydro Turbines in Power System Studies&quot; published in 1973 which apply to such phrase.</td>
</tr>
<tr>
<td>Type A Power Generating Module</td>
<td>A Power-Generating Module (including an Electricity Storage 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;</td>
</tr>
<tr>
<td>Type B Power Generating Module</td>
<td>A Power-Generating Module (including an Electricity Storage 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;</td>
</tr>
<tr>
<td>Type C Power Generating Module</td>
<td>A Power-Generating Module (including an Electricity Storage 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;</td>
</tr>
<tr>
<td>Type D Power Generating Module</td>
<td>A Power-generating Module (including an Electricity Storage 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</td>
</tr>
<tr>
<td>Unbalanced Load</td>
<td>The situation where the Load on each phase is not equal.</td>
</tr>
<tr>
<td>Under-excitation Limiter</td>
<td>Shall have the meaning ascribed to that term in IEC 34-16-1:1991 [equivalent to British Standard BS4999 Section 116.1: 1992].</td>
</tr>
<tr>
<td><strong>Under Frequency Relay</strong></td>
<td>An electrical measuring relay intended to operate when its characteristic quantity (<strong>Frequency</strong>) reaches the relay settings by a decrease in <strong>Frequency</strong>.</td>
</tr>
<tr>
<td><strong>Unit Board</strong></td>
<td>A switchboard through which electrical power is supplied to the <strong>Auxiliaries</strong> of a <strong>Generating Unit</strong> and which is supplied by a <strong>Unit Transformer</strong>. It may be interconnected with a <strong>Station Board</strong>.</td>
</tr>
<tr>
<td><strong>Unit Transformer</strong></td>
<td>A transformer directly connected to a <strong>Generating Unit's</strong> terminals, and which supplies power to the <strong>Auxiliaries</strong> of a <strong>Generating Unit</strong>. Typical voltage ratios are 23/11kV and 15/6.6kV.</td>
</tr>
<tr>
<td><strong>Unit Load Controller Response Time Constant</strong></td>
<td>The time constant, expressed in units of seconds, of the power output increase which occurs in the <strong>Secondary Response</strong> timescale in response to a step change in <strong>System Frequency</strong>.</td>
</tr>
<tr>
<td><strong>Unresolved Issues</strong></td>
<td>Any relevant Grid Code provisions or <strong>Bilateral Agreement</strong> requirements identified by <strong>The Company</strong> with which the relevant <strong>User</strong> has not demonstrated compliance to <strong>The Company's</strong> reasonable satisfaction at the date of issue of the <strong>Preliminary Operational Notification</strong> and/or <strong>Interim Operational Notification</strong> and/or <strong>Limited Operational Notification</strong> and which are detailed in such <strong>Preliminary Operational Notification</strong> and/or <strong>Interim Operational Notification</strong> and/or <strong>Limited Operational Notification</strong>.</td>
</tr>
<tr>
<td><strong>Urgent Modification</strong></td>
<td>A <strong>Grid Code Modification Proposal</strong> treated or to be treated as an <strong>Urgent Modification</strong> in accordance with GR.23.</td>
</tr>
<tr>
<td><strong>User</strong></td>
<td>A term utilised in various sections of the Grid Code to refer to the persons using the <strong>National Electricity Transmission System</strong>, as more particularly identified in each section of the Grid Code concerned. In the <strong>Preface</strong> and the <strong>General Conditions</strong> the term means any person to whom the Grid Code applies. The term <strong>User</strong> includes an <strong>EU Code User</strong> and a <strong>GB Code User</strong>.</td>
</tr>
<tr>
<td><strong>User Data File Structure</strong></td>
<td>The file structure given at <strong>DRC 18</strong> which will be specified by <strong>The Company</strong> which a <strong>Generator</strong> or <strong>DC Converter Station</strong> owner or <strong>HVDC System Owner</strong> must use for the purposes of the <strong>CP</strong> or the <strong>ECP</strong> to submit <strong>DRC data Schedules</strong> and information demonstrating compliance with the Grid Code and, where applicable, with the <strong>CUSC Contract(s)</strong>, unless otherwise agreed by <strong>The Company</strong>.</td>
</tr>
<tr>
<td><strong>User Development</strong></td>
<td>In the <strong>PC</strong> means either <strong>User's Plant</strong> and/or <strong>Apparatus</strong> to be connected to the <strong>National Electricity Transmission System</strong>, or a <strong>Modification</strong> relating to a <strong>User's Plant</strong> and/or <strong>Apparatus</strong> already connected to the <strong>National Electricity Transmission System</strong>, or a proposed new connection or <strong>Modification</strong> to the connection within the <strong>User System</strong>.</td>
</tr>
<tr>
<td><strong>User Self Certification of Compliance</strong></td>
<td>A certificate, in the form attached at <strong>CP.A.2.(1)</strong> or <strong>ECP.A.2.(1)</strong> completed by a <strong>Generator</strong> or <strong>DC Converter Station</strong> owner or <strong>HVDC System Owner</strong> to which the <strong>Compliance Statement</strong> is attached which confirms that such <strong>Plant</strong> and <strong>Apparatus</strong> complies with the relevant Grid Code provisions and where appropriate, with the <strong>CUSC Contract(s)</strong>, as identified in the <strong>Compliance Statement</strong> and, if appropriate, identifies any <strong>Unresolved Issues</strong> and/or any exceptions to such compliance and details the derogation(s) granted in respect of such exceptions.</td>
</tr>
<tr>
<td><strong>User Site</strong></td>
<td>A site owned (or occupied pursuant to a lease, licence or other agreement) by a <strong>User</strong> in which there is a <strong>Connection Point</strong>. For the avoidance of doubt, a site owned by a <strong>Relevant Transmission Licensee</strong> but occupied by a <strong>User</strong> as aforesaid, is a <strong>User Site</strong>.</td>
</tr>
<tr>
<td>---------------</td>
<td>--------------------------------------------------------------------------------------------------</td>
</tr>
</tbody>
</table>
| **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 an **Electricity Storage Module** or a **DC Converter** or an **HVDC Converter**, as the case may be, which is **Embedded** connects to the **User System**. |
| **Voltage Jump Reactive Power** | The transient **Reactive Power** injected or absorbed from a **Grid Forming Plant** to the **Total System** as a result of either a step or ramp change in the difference between the voltage magnitude and/or phase of the voltage of the **Internal Voltage Source** of the **Grid Forming Plant** and **Grid Entry Point** or **User System Entry Point**.  
In the event of a voltage magnitude and phase change at the **Grid Entry Point** or **User System Entry Point**, a **Grid Forming Plant** will instantaneously (within 5ms) supply **Voltage Jump Reactive Power** to the **Total System** as a result of the voltage magnitude change. |
<p>| <strong>Water Time Constant</strong> | Bears the meaning ascribed to the term &quot;Water inertia time&quot; in IEC308. |
| <strong>Website</strong> | The site established by <strong>The Company</strong> on the World-Wide Web for the exchange of information among <strong>Users</strong> and other interested persons in accordance with such restrictions on access as may be determined from time to time by <strong>The Company</strong>. |</p>
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<th><strong>Weekly ACS Conditions</strong></th>
<th>Means that particular combination of weather elements that gives rise to a level of peak <strong>Demand</strong> 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 <strong>Demand</strong> in all weeks of the year exceeding the annual peak <strong>Demand</strong> under <strong>Annual ACS Conditions</strong> is 50%, and in the week of maximum risk the weekly peak <strong>Demand</strong> under <strong>Weekly ACS Conditions</strong> is equal to the annual peak <strong>Demand</strong> under <strong>Annual ACS Conditions</strong>.</th>
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<td>Any request from an <strong>Authorised Electricity Operator</strong>; the <strong>Citizens Advice</strong> or the <strong>Citizens Advice Scotland</strong>; The Company or a <strong>Materially Affected Party</strong> for a <strong>Workgroup Alternative Grid Code Modification</strong> to be developed by the <strong>Workgroup</strong> expressed as such and which contains the information referred to at <strong>GR.20.16</strong>. For the avoidance of doubt, any <strong>WG Consultation Alternative Request</strong> does not constitute either a <strong>Grid Code Modification Proposal</strong> or a <strong>Workgroup Alternative Grid Code Modification</strong>.</td>
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<tr>
<td><strong>Workgroup</strong></td>
<td>A <strong>Workgroup</strong> established by the <strong>Grid Code Review Panel</strong> pursuant to <strong>GR.20.1</strong>;</td>
</tr>
<tr>
<td><strong>Workgroup Consultation</strong></td>
<td>As defined in <strong>GR.20.13</strong>, and any further consultation which may be directed by the <strong>Grid Code Review Panel</strong> pursuant to <strong>GR.20.20</strong>;</td>
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<td><strong>Workgroup Alternative Grid Code Modification</strong></td>
<td>An alternative modification to the <strong>Grid Code Modification Proposal</strong> developed by the <strong>Workgroup</strong> under the <strong>Workgroup</strong> terms of reference (either as a result of a <strong>Workgroup Consultation</strong> or otherwise) and which is believed by a majority of the members of the <strong>Workgroup</strong> or by the chairperson of the <strong>Workgroup</strong> to better facilitate the <strong>Grid Code Objectives</strong> than the <strong>Grid Code Modification Proposal</strong> or the current version of the <strong>Grid Code</strong>;</td>
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<tr>
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<td>That generation required, within the boundary circuits defining the <strong>System Zone</strong>, which when added to the secured transfer capability of the boundary circuits exactly matches the <strong>Demand</strong> within the <strong>System Zone</strong>.</td>
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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. Retained EU Law (Commission 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.

(xiv) Except where expressly stated to the contrary, reference to Commission Regulations means the Commission Regulation (EU) as it forms part of Retained EU Law, as such regulation may be amended.

< END OF GLOSSARY & DEFINITIONS>
# PLANNING CODE

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INTRODUCTION

PC.1.1
The Planning Code ("PC") specifies the technical and design criteria and procedures to be applied by The Company in the planning and development of the National Electricity Transmission System and to be taken into account by Users in the planning and development of their own Systems. In the case of OTSUA, the PC also specifies the technical and design criteria and procedures to be applied by the User in the planning and development of the OTSUA. It details information to be supplied by Users to The Company, and certain information to be supplied by The Company to Users. The Company has obligations under the STC to inform Relevant Transmission Licensees of data required for the planning of the National Electricity Transmission System. In respect of PC data, The Company may pass on User data to a Relevant Transmission Licensee, as detailed in PC.3.4 and PC.3.5.

PC.1.1A
Provisions of the PC which apply in relation to OTSDUW and OTSUA shall apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply, without prejudice to the continuing application of provisions of the PC applying in relation to the relevant Offshore Transmission System and/or Connection Site.

PC.1.1B
As used in the PC:

(a) National Electricity Transmission System excludes OTSDUW Plant and Apparatus (prior to the OTSUA Transfer Time) unless the context otherwise requires;

(b) and User Development includes OTSDUW unless the context otherwise requires.

PC.1.2
The Users referred to above are defined, for the purpose of the PC, in PC.3.1.

PC.1.3
Development of the National Electricity Transmission System, involving its reinforcement or extension, will arise for a number of reasons including, but not limited to:

(a) a development on a User System already connected to the National Electricity Transmission System;

(b) the introduction of a new Connection Site or the Modification of an existing Connection Site between a User System and the National Electricity Transmission System;

(c) the cumulative effect of a number of such developments referred to in (a) and (b) by one or more Users.

PC.1.4
Accordingly, the reinforcement or extension of the National Electricity Transmission System may involve work:

(a) at a substation at a Connection Site where User's Plant and/or Apparatus is connected to the National Electricity Transmission System (or in the case of OTSDUW, at a substation at an Interface Point);

(b) on transmission lines or other facilities which join that Connection Site (or in the case of OTSDUW, Interface Point) to the remainder of the National Electricity Transmission System;

(c) on transmission lines or other facilities at or between points remote from that Connection Site (or in the case of OTSDUW, Interface Point).

PC.1.5
The time required for the planning and development of the National Electricity Transmission System will depend on the type and extent of the necessary reinforcement and/or extension work, the need or otherwise for statutory planning consent, the associated possibility of the need for a public inquiry and the degree of complexity in undertaking the new work while maintaining satisfactory security and quality of supply on the existing National Electricity Transmission System.
For the avoidance of doubt and the purposes of the Grid Code, DC Connected Power Park Modules are treated as belonging to Generators. Generators who own DC Connected Power Park Modules would therefore be expected to supply the same data as required under this PC in respect of Power Stations comprising Power Park Modules other than where specific references to DC Connected Power Park Modules are made.

As defined in the Glossary and Definitions, Electricity Storage Modules are treated as belonging to Storage User’s who are a subset of Generator’s. Generators who own or operate Electricity Storage Modules would therefore be expected to supply the same data as required under this PC in respect of Power Stations. In general, and not withstanding the requirements of the Glossary and Definitions and the wider requirements specified in the Planning Code, Generators in respect of Synchronous Electricity Storage Modules would be expected to supply the same data as required from Generators in respect of Synchronous Power Generating Modules and Generators in respect of Non-Synchronous Electricity Storage Modules would be expected to supply the same data as required from Generators in respect of Power Park Modules.

The objectives of the PC are:

(a) to promote The Company/User interaction in respect of any proposed development on the User System which may impact on the performance of the National Electricity Transmission System or the direct connection with the National Electricity Transmission System;

(b) to provide for the supply of information to The Company from Users in order that planning and development of the National Electricity Transmission System can be undertaken in accordance with the relevant Licence Standards, to facilitate existing and proposed connections, and also to provide for the supply of certain information from The Company to Users in relation to short circuit current contributions and OTSUA; and

(c) to specify the Licence Standards which will be used in the planning and development of the National Electricity Transmission System; and

(d) to provide for the supply of information required by The Company from Users in respect of the following to enable The Company to carry out its duties under the Act and the Transmission Licence:

(i) Mothballed Generating Units, Mothballed Power Generating Modules; and

(ii) capability of gas-fired Synchronous Power Generating Modules or Generating Units to run using alternative fuels.

The Company will use the information provided under PC.2.1(d) in providing reports to the Authority and the Secretary of State and, where directed by the Authority or the Secretary of State to do so, The Company may publish the information. Where it is known by The Company that such information is intended for wider publication the information provided under PC.2.1(d) shall be aggregated such that individual data items should not be identifiable.

(e) in the case of OTSUA:

(i) to specify the minimum technical and design criteria and procedures to be applied by Users in the planning and development of OTSUA; and thereby

(ii) to ensure that the OTSUA can from the OTSUA Transfer Time be operated as part of the National Electricity Transmission System; and

(iii) to provide for the arrangements and supply of information and data between The Company and a User to ensure that the User is able to undertake OTSDUW; and

(iv) to promote The Company/User interaction and co-ordination in respect of any proposed development on the National Electricity Transmission System or the OTSUA, which may impact on the OTSUA or (as the case may be) the National Electricity Transmission System.
SCOPE

The PC applies to The Company and to Users, which in the PC means:

(a) Generators;
(b) Generators undertaking OTSDUW;
(c) Network Operators;
(d) Non-Embedded Customers;
(e) DC Converter Station owners; and
(f) HVDC System Owners.

The above categories of User will become bound by the PC prior to them generating, operating, or consuming or importing/exporting, as the case may be, and references to the various categories (or to the general category) of User should, therefore, be taken as referring to them in that prospective role as well as to Users actually connected.

In the case of Embedded Power Stations, Embedded DC Converter Stations and Embedded HVDC Systems, unless provided otherwise, the following provisions apply with regard to the provision of data under this PC:

(a) each Generator shall provide the data direct to The Company in respect of (i) Embedded Large Power Stations, (ii) Embedded Medium Power Stations subject to a Bilateral Agreement and (iii) Embedded Small Power Stations which form part of a Cascade Hydro Scheme;
(b) each DC Converter owner or HVDC System Owner shall provide the data direct to The Company in respect of Embedded DC Converter Stations and Embedded HVDC Systems subject to a Bilateral Agreement;
(c) each Network Operator shall provide the data to The Company in respect of each Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded DC Converter Station not subject to a Bilateral Agreement or Embedded HVDC System not subject to a Bilateral Agreement connected, or proposed to be connected within such Network Operator's System;
(d) although data is not normally required specifically on Embedded Small Power Stations or on Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System under this PC, each Network Operator in whose System they are Embedded should provide the data (contained in the Appendix) to The Company in respect of Embedded Small Power Stations or Embedded installations of HVDC Systems if:
   (i) it falls to be supplied pursuant to the application for a CUSC Contract or in the Statement of Readiness to be supplied in connection with a Bilateral Agreement and/or Construction Agreement, by the Network Operator; or
   (ii) it is specifically requested by The Company in the circumstances provided for under this PC.

Certain data does not normally need to be provided in respect of certain Embedded Power Stations, Embedded DC Converter Stations or Embedded HVDC Systems, as provided in PC.A.1.12.

In summary, Network Operators are required to supply the following data in respect 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 Systems not subject to a Bilateral Agreement connected, or is proposed to be connected, within such Network Operator's System:
For the avoidance of doubt Network Operators are required to supply the above data in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement which are located Offshore and which are connected or proposed to be connected within such Network Operator’s System. This is because Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement are treated as Onshore Generators or Onshore DC Converter Station owners or HVDC System Owners connected to an Onshore User System Entry Point.

The Company may provide to the Relevant Transmission Licensees any data which has been submitted to The Company by any Users pursuant to the following paragraphs of the PC. For the avoidance of doubt, The Company will not provide to the Relevant Transmission Licensees, the types of data specified in Appendix D. The Relevant Transmission Licensees’ use of such data is detailed in the STC.
PC.A.5.4.3.2
PC.A.5.4.3.3
PC.A.5.4.3.4
PC.A.7
(and in addition in respect of the data submitted in respect of the OTSUA)
PC.A.2.2
PC.A.2.3
PC.A.2.4
PC.A.2.5
PC.A.3.2.2
PC.A.3.3.1(d)
PC.A.4
PC.A.5.4.3.1
PC.A.5.4.3.2
PC.A.6.2
PC.A.6.3
PC.A.6.4
PC.A.6.5
PC.A.6.6
PC.A.7

PC.3.5 In addition to the provisions of PC.3.4, The Company may provide to the Relevant Transmission Licensees any data which has been submitted to The Company by any Users in respect of Relevant Units pursuant to the following paragraphs of the PC.
PC.A.2.3
PC.A.2.4
PC.A.5.5
PC.A.5.7
PC.A.6.2
PC.A.6.3
PC.A.6.4
PC.A.6.5
PC.A.6.6

PC.3.6 In the case of Offshore Embedded Power Stations connected to an Offshore User System which directly connects to an Offshore Transmission System, any additional data requirements in respect of such Offshore Embedded Power Stations may be specified in the relevant Bilateral Agreement with the Network Operator or in any Bilateral Agreement between The Company and such Offshore Embedded Power Station.

PC.3.7 In the case of a Generator undertaking OTSDUW connecting to an Onshore Network Operator’s System, any additional requirements in respect of such OTSDUW Plant and Apparatus will be specified in the relevant Bilateral Agreement with the Generator. For the avoidance of doubt, requirements applicable to Generators undertaking OTSDUW and connecting to a Network Operator’s User System, shall be consistent with those applicable requirements of Generators undertaking OTSDUW and connecting to a Transmission Interface Point.
PLANNING PROCEDURES

PC.4.1 Pursuant to Condition C11 of The Company’s Transmission Licence, the means by which Users and proposed Users of the National Electricity Transmission System are able to assess opportunities for connecting to, and using, the National Electricity Transmission System comprise two distinct parts, namely:

(a) a statement, prepared by The Company under its 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 (the “Seven Year Statement”); and

(b) an offer, in accordance with its Transmission Licence, by The Company to enter into a CUSC Contract. A Bilateral Agreement is to be entered into for every Connection Site (and for certain Embedded Power Stations and Embedded DC Converter Stations and Embedded HVDC Systems) within the first two of the following categories and the existing Bilateral Agreement may be required to be varied in the case of the third category:

(i) existing Connection Sites (and for certain Embedded Power Stations) as at the Transfer Date;

(ii) new Connection Sites (and for certain Embedded Power Stations, Embedded DC Converter Stations and Embedded HVDC Systems) with effect from the Transfer Date;

(iii) a Modification at a Connection Site (or in relation to the connection of certain Embedded Power Stations, Embedded DC Converter Stations and Embedded HVDC Systems whether or not the subject of a Bilateral Agreement) (whether such Connection Site or connection exists on the Transfer Date or is new thereafter) with effect from the Transfer Date.

In this PC, unless the context otherwise requires, “connection” means any of these 3 categories.

Introduction to Data

User Data

PC.4.2.1 Under the PC, two types of data to be supplied by Users are called for:

(a) Standard Planning Data; and

(b) Detailed Planning Data,

as more particularly provided in PC.A.1.4.

PC.4.2.2 The PC recognises that these two types of data, namely Standard Planning Data and Detailed Planning Data, are considered at three different levels:

(a) Preliminary Project Planning Data;

(b) Committed Project Planning Data; and

(c) Connected Planning Data,

as more particularly provided in PC.5

PC.4.2.3 Connected Planning Data is itself divided into:

(a) Forecast Data;

(b) Registered Data; and

(c) Estimated Registered Data,

as more particularly provided in PC.5.5
Clearly, an existing User proposing a new Connection Site (or Embedded Power Station or Embedded DC Converter Station or Embedded HVDC System) in the circumstances outlined in PC.4.1 will need to supply data both in an application for a Bilateral Agreement and under the PC in relation to that proposed new Connection Site (or Embedded Power Station or Embedded DC Converter Station or Embedded HVDC System) in the circumstances outlined in PC.4.1 and that will be treated as Preliminary Project Planning Data or Committed Project Planning Data (as the case may be), but the data it supplies under the PC relating to its existing Connection Sites will be treated as Connected Planning Data.

Network Data

PC.4.2.5

In addition, there is Network Data supplied by The Company in relation to short circuit current contributions and in relation to OTSUA.

PC.4.3

Data Provision

PC.4.3.1

Seven Year Statement

To enable the Seven Year Statement to be prepared, each User is required to submit to The Company (subject to the provisions relating to Embedded Power Stations and Embedded DC Converter Stations and Embedded HVDC Systems in PC.3.2) both the Standard Planning Data and the Detailed Planning Data as listed in parts 1 and 2 of the Appendix. This data should be submitted in calendar week 24 of each year (although Network Operators may delay the submission of data (other than that to be submitted pursuant to PC.3.2(c) and PC.3.2(d)) until calendar week 28) and should cover each of the seven succeeding Financial Years (and in certain instances, the current year). Where, from the date of one submission to another, there is no change in the data (or in some of the data) to be submitted, instead of re-submitting the data, a User may submit a written statement that there has been no change from the data (or in some of the data) submitted the previous time. In addition, The Company will also use the Transmission Entry Capacity and Connection Entry Capacity data from the CUSC Contract, and any data submitted by Network Operators in relation to an Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded DC Converter Station not subject to a Bilateral Agreement, or Embedded HVDC System not subject to a Bilateral Agreement in the preparation of the Seven Year Statement and to that extent the data will not be treated as confidential.

PC.4.3.2

Network Data

To enable Users to model the National Electricity Transmission System in relation to short circuit current contributions, The Company is required to submit to Users, the Network Data as listed in Part 3 of the Appendix. The data will be submitted in week 42 of each year and will cover that Financial Year.

PC.4.3.3

To enable Users to model the National Electricity Transmission System in relation to OTSUA, The Company is required to submit to Users the Network Data, as listed in Part 3 of Appendix A and Appendix F. The Company shall provide the Network Data with the offer of a CUSC Contract in the case of the data in PC F2.1 and otherwise in accordance with the OTSDUW Development and Data Timetable.

PC.4.4

Offer of Terms for Connection

PC.4.4.1

CUSC Contract – Data Requirements/Offer Timing

The completed application form for a CUSC Contract to be submitted by a User when making an application for a CUSC Contract will include:

(a) a description of the Plant and/or Apparatus (excluding OTSDUW Plant and Apparatus) to be connected to the National Electricity Transmission System or of the Modification relating to the User's Plant and/or Apparatus (and prior to the OTSUA Transfer Time, any OTSUA) already connected to the National Electricity Transmission System or, as the case may be, of the proposed new connection or Modification to the connection within the User System of the User, each of which shall be termed a "User Development" in the PC;
(b) the relevant Standard Planning Data as listed in Part 1 of the Appendix (except in respect of any OTSUA); and

c) the desired Completion Date of the proposed User Development.

d) the desired Connection Entry Capacity and Transmission Entry Capacity.

The completed application form for a CUSC Contract will be sent to The Company as more particularly provided in the application form.

PC.4.4.2 Any offer of a CUSC Contract will provide that it must be accepted by the applicant User within the period stated in the offer, after which the offer automatically lapses. Except as provided in the CUSC Contract, acceptance of the offer renders the National Electricity Transmission System works relating to that User Development, reflected in the offer, committed and binds both parties to the terms of the offer. The User shall then provide the Detailed Planning Data as listed in Part 2 of the Appendix (and in the case of OTSUA the Standard Planning Data as listed in Part 1 of Appendix A within the timeline provided in PC.A.1.4). In respect of DPD I this shall generally be provided within 28 days (or such shorter period as The Company may determine, or such longer period as The Company may agree, in any particular case) of acceptance of the offer and in respect of DPD II this shall generally be provided at least two years (or such longer period as The Company may determine, or such shorter period as The Company may agree, in any particular case or in the case of OTSUA such shorter period as The Company shall require) prior to the Completion Date of the User Development.

PC.4.4.3 Embedded Development Agreement - Data Requirements

The Network Operator shall submit the following data in relation to an Embedded Medium Power Station not subject to, or proposed to be subject to, a Bilateral Agreement or Embedded DC Converter Station not subject to, or proposed to be subject to, a Bilateral Agreement as soon as reasonably practicable after receipt of an application from an Embedded Person to connect to its System:

(a) details of the proposed new connection or variation (having a similar effect on the Network Operator’s System as a Modification would have on the National Electricity Transmission System) to the connection within the Network Operator’s System, each of which shall be termed an “Embedded Development” in the PC (where a User Development has an impact on the Network Operator’s System details shall be supplied in accordance with PC.4.4 and PC.4.5);

(b) the relevant Standard Planning Data as listed in Part 1 of the Appendix;

c) the proposed completion date (having a similar meaning in relation to the Network Operator’s System as Completion Date would have in relation to the National Electricity Transmission System) of the Embedded Development; and

d) upon the request of The Company, the relevant Detailed Planning Data as listed in Part 2 of the Appendix.

PC.4.4.4 The Network Operator shall provide the Detailed Planning Data as listed in Part 2 of the Appendix. In respect of DPD I, this shall generally be provided within 28 days (or such shorter period as The Company may determine, or such longer period as The Company may agree, in any particular case) of entry into the Embedded Development Agreement and in respect to DPD II this shall generally be provided at least two years (or such longer period as The Company may determine, or such shorter period as The Company may agree, in any particular case) prior to the Completion Date of the Embedded Development.

PC.4.5 Complex Connections
PC.4.5.1 The magnitude and complexity of any National Electricity Transmission System extension or reinforcement will vary according to the nature, location and timing of the proposed User Development which is the subject of the application and it may, in the event, be necessary for The Company to carry out additional more extensive system studies to evaluate more fully the impact of the proposed User Development on the National Electricity Transmission System. Where The Company judges that such additional more detailed studies are necessary the offer may indicate the areas that require more detailed analysis and before such additional studies are required, the User shall indicate whether it wishes The Company to undertake the work necessary to proceed to make a revised offer within the 3 month period normally allowed or, where relevant, the timescale consented to by the Authority.

PC.4.5.2 To enable The Company to carry out any of the above mentioned necessary detailed system studies, the User may, at the request of The Company, be required to provide some or all of the Detailed Planning Data listed in part 2 of the Appendix in advance of the normal timescale referred in PC.4.4.2 provided that The Company can reasonably demonstrate that it is relevant and necessary.

PC.4.5.3 To enable The Company to carry out any necessary detailed system studies, the relevant Network Operator may, at the request of The Company, be required to provide some or all of the Detailed Planning Data listed in Part 2 of the Appendix in advance of the normal timescale referred in PC.4.4.4 provided that The Company can reasonably demonstrate that it is relevant and necessary.

PC.5 PLANNING DATA

PC.5.1 As far as the PC is concerned, there are three relevant levels of data in relation to Users. These levels, which relate to levels of confidentiality, commitment and validation, are described in the following paragraphs.

Preliminary Project Planning Data

PC.5.2 At the time the User applies for a CUSC Contract but before an offer is made and accepted by the applicant User, the data relating to the proposed User Development will be considered as Preliminary Project Planning Data. Data relating to an Embedded Development provided by a Network Operator in accordance with PC.4.4.3, and PC.4.4.4 if requested, will be considered as Preliminary Project Planning Data. All such data will be treated as confidential within the scope of the provisions relating to confidentiality in the CUSC.

PC.5.3 Preliminary Project Planning Data will normally only contain the Standard Planning Data unless the Detailed Planning Data is required in advance of the normal timescale to enable The Company to carry out additional detailed system studies as described in PC.4.5.

Committed Project Planning Data

PC.5.4 Once the offer for a CUSC Contract is accepted, the data relating to the User Development already submitted as Preliminary Project Planning Data, and subsequent data required by The Company under this PC, will become Committed Project Planning Data. Once an Embedded Person has entered into an Embedded Development Agreement, as notified to The Company by the Network Operator, the data relating to the Embedded Development already submitted as Preliminary Project Planning Data, and subsequent data required by The Company under the PC, will become Committed Project Planning Data. Such data, together with Connection Entry Capacity and Transmission Entry Capacity data from the CUSC Contract and other data held by The Company relating to the National Electricity Transmission System will form the background against which new applications by any User will be considered and against which planning of the National Electricity Transmission System will be undertaken. Accordingly, Committed Project Planning Data, Connection Entry Capacity and Transmission Entry Capacity data will not be treated as confidential to the extent that The Company:

(a) is obliged to use it in the preparation of the Seven Year Statement and in any further information given pursuant to the Seven Year Statement;
(b) is obliged to use it when considering and/or advising on applications (or possible applications) of other Users (including making use of it by giving data from it, both orally and in writing, to other Users making an application (or considering or discussing a possible application) which is, in The Company’s view, relevant to that other application or possible application);

(c) is obliged to use it for operational planning purposes;

(d) is obliged under the terms of an Interconnection Agreement to pass it on as part of system information on the Total System;

(e) is obliged to disclose it under the STC;

(f) is obliged to use and disclose it in the preparation of the Offshore Development Information Statement;

(g) is obliged to use it in order to carry out its EMR Functions or is obliged to disclose it under an EMR Document.

To reflect different types of data, Preliminary Project Planning Data and Committed Project Planning Data are themselves divided into:

(a) those items of Standard Planning Data and Detailed Planning Data which will always be forecast, known as Forecast Data; and

(b) those items of Standard Planning Data and Detailed Planning Data which relate to Plant and/or Apparatus which upon connection will become Registered Data, but which prior to connection, for the seven succeeding Financial Years, will be an estimate of what is expected, known as Estimated Registered Data.

Connected Planning Data

The PC requires that, at the time that a Statement of Readiness is submitted under the Bilateral Agreement and/or Construction Agreement, any estimated values assumed for planning purposes are confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for forecast data items such as Demand. In the case of an Embedded Development the relevant Network Operator will update any estimated values assumed for planning purposes with validated actual values as soon as reasonably practicable after energisation. This data is then termed Connected Planning Data.

To reflect the three types of data referred to above, Connected Planning Data is itself divided into:

(a) those items of Standard Planning Data and Detailed Planning Data which will always be forecast data, known as Forecast Data; and

(b) those items of Standard Planning Data and Detailed Planning Data which upon connection become fixed (subject to any subsequent changes), known as Registered Data; and

(c) those items of Standard Planning Data and Detailed Planning Data which for the purposes of the Plant and/or Apparatus concerned as at the date of submission are Registered Data but which for the seven succeeding Financial Years will be an estimate of what is expected, known as Estimated Registered Data,

as more particularly provided in the Appendix.

PC.5.6

Connected Planning Data, together with Connection Entry Capacity and Transmission Entry Capacity data from the CUSC Contract, and other data held by The Company relating to the National Electricity Transmission System, will form the background against which new applications by any User will be considered and against which planning of the National Electricity Transmission System will be undertaken. Accordingly, Connected Planning Data, Connection Entry Capacity and Transmission Entry Capacity data will not be treated as confidential to the extent that The Company:
(a) is obliged to use it in the preparation of the **Seven Year Statement** and in any further information given pursuant to the **Seven Year Statement**;

(b) is obliged to use it when considering and/or advising on applications (or possible applications) of other **Users** (including making use of it by giving data from it, both orally and in writing, to other **Users** making an application (or considering or discussing a possible application) which is, in **The Company’s** view, relevant to that other application or possible application);

(c) is obliged to use it for operational planning purposes;

(d) is obliged under the terms of an **Interconnection Agreement** to pass it on as part of system information on the **Total System**.

(e) is obliged to disclose it under the **STC**;

(f) is obliged to use it in order to carry out its **EMR Functions** or is obliged to disclose it under an **EMR Document**.

**PC.5.7**

**Committed Project Planning Data** and **Connected Planning Data** will each contain both **Standard Planning Data** and **Detailed Planning Data**.
PC.6 PLANNING STANDARDS

PC.6.1 The Company shall apply the Licence Standards relevant to it in the planning and development of the National Electricity Transmission System. The Company shall procure that each Relevant Transmission Licensee shall apply the Licence Standards relevant to planning and development, in the planning and development of the Transmission System of each Relevant Transmission Licensee and that a User shall apply the Licence Standards relevant to planning and development, in the planning and development of the OTSUA.

PC.6.2 In relation to Scotland, Appendix C lists the technical and design criteria applied in the planning and development of each Relevant Transmission Licensee's Transmission System. The criteria are subject to review in accordance with each Relevant Transmission Licensee's Transmission Licence conditions. Copies of these documents are available from The Company on request. The Company will charge an amount sufficient to recover its reasonable costs incurred in providing this service.

PC.6.3 In relation to Offshore, Appendix E lists the technical and design criteria applied in the planning and development of each Offshore Transmission System. The criteria are subject to review in accordance with each Offshore Transmission Licensee’s Transmission Licence conditions. Copies of these documents are available from The Company on request. The Company will charge an amount sufficient to recover its reasonable costs incurred in providing this service.

PC.6.4 In planning and developing the OTSUA, the User shall comply with (and shall ensure that (as at the OTSUA Transfer Time) the OTSUA comply with):

(a) the Licence Standards; and

(b) the technical and design criteria in Appendix E.

PC.6.5 In addition the User shall, in the planning and development of the OTSUA, to the extent it is reasonable and practicable to do so, take into account the reasonable requests of The Company (in the context of its obligation to develop an efficient, co-ordinated and economical system) relating to the planning and development of the National Electricity Transmission System.

PC.6.6 In planning and developing the OTSUA the User shall take into account the Network Data provided to it by The Company under Part 3 of Appendix A and Appendix F, and act on the basis that the Plant and Apparatus of other Users complies with:

(a) the minimum technical design and operational criteria and performance requirements set out in either CC.6.1, CC.6.2, CC.6.3 and CC.6.4 or ECC.6.1, ECC.6.2, ECC.6.3 and ECC.6.4; or

(b) such other criteria or requirements as The Company may from time to time notify the User are applicable to specified Plant and Apparatus pursuant to PC.6.7.

PC.6.7 Where the OTSUA are likely to be materially affected by the design or operation of another User's Plant and Apparatus and The Company:

(a) becomes aware that such other User has or is likely to apply for a derogation under the Grid Code;

(b) is itself applying for a derogation under the Grid Code in relation to the Connection Site on which such other User’s Plant and Apparatus is located or to which it otherwise relates; or

(c) is otherwise notified by such other User that specified Plant or Apparatus is normally capable of operating at levels better than those set out in CC.6.1, CC.6.2, CC.6.3 and CC.6.4 or ECC.6.1, ECC.6.2, ECC.6.3 and ECC.6.4,

The Company shall notify the User.
PC.7 PLANNING LIAISON

PC.7.1 This PC.7 applies to The Company and Users, which in PC.7 means

(a) Network Operators

(b) Non-Embedded Customers

PC.7.2 As described in PC.2.1 (b) an objective of the PC is to provide for the supply of information to The Company by Users in order that planning and development of the National Electricity Transmission System can be undertaken in accordance with the relevant Licence Standards.

PC.7.3 Grid Code amendment B/07 (“Amendment B/07”) implemented changes to the Grid Code which included amendments to the datasets provided by both The Company and Users to inform the planning and development of the National Electricity Transmission System. The Authority has determined that these changes are to have a phased implementation. Consequently the provisions of Appendix A to the PC include specific years (ranging from 2009 to 2011) with effect from which certain of the specific additional obligations brought about by Amendment B/07 on The Company and Users are to take effect. Where specific provisions of paragraphs PC.A.4.1.4, PC.A.4.2.2 and PC.A.4.3.1 make reference to a year, then the obligation on The Company and the Users shall be required to be met by the relevant calendar week (as specified within such provision) in such year.

In addition to the phased implementation of aspects of Amendment B/07, Users must discuss and agree with The Company by no later than 31 March 2009 a more detailed implementation programme to facilitate the implementation of Grid Code amendment B/07.

It shall also be noted by The Company and Users that the dates set out in PC.A.4 are intended to be minimum requirements and are not intended to restrict a User and The Company from the earlier fulfilment of the new requirements prior to the specified years. Where The Company and a User wish to follow the new requirements from earlier dates than those specified, this will be set out in the more detailed implementation programme agreed between The Company and the User.

The following provisions of PC.7 shall only apply with effect from 1 January 2011.

PC.7.4 Following the submission of data by a User in or after week 24 of each year The Company will provide information to Users by calendar week 6 of the following year regarding the results of any relevant assessment that has been made by The Company based upon such data submissions to verify whether Connection Points are compliant with the relevant Licence Standards.

PC.7.5 Where the result of any assessment identifies possible future non-compliance with the relevant Licence Standards, The Company shall notify the relevant User(s) of this fact as soon as reasonably practicable and shall agree with Users any opportunity to resubmit data to allow for a reassessment in accordance with PC.7.6.

PC.7.6 Following any notification by The Company to a User pursuant to PC.7.5 and following any further discussions held between the User and The Company:

(i) The Company and the User may agree revisions to the Access Periods for relevant Transmission Interface Circuits, such revisions shall not however permit an Access Period to be less than 4 continuous weeks in duration or to occur other than between calendar weeks 10 and 43 (inclusive); and/or

(ii) The User shall as soon as reasonably practicable

(a) submit further relevant data to The Company that is to The Company’s reasonable satisfaction; and/or,

(b) modify data previously submitted pursuant to this PC, such modified data to be to The Company’s reasonable satisfaction; and/or

(c) notify The Company that it is the intention of the User to leave the data as originally submitted to The Company to stand as its submission.
Where an Access Period is amended pursuant to PC.7.6 (i) The Company shall notify The Authority that it has been necessary to do so.

When it is agreed that any resubmission of data is unlikely to confirm future compliance with the relevant Licence Standards the Modification process in the CUSC may apply.

A User may at any time, in writing, request further specified National Electricity Transmission System network data in order to provide The Company with viable User network data (as required under this PC). Upon receipt of such request, The Company shall consider, and where appropriate provide such National Electricity Transmission System network data to the User as soon as reasonably practicable following the request.

OTSDUW PLANNING LIAISON

This PC.8 applies to The Company and Users, which in PC.8 means Users undertaking OTSDUW.

As described in PC.2.1 (e) an objective of the PC is to provide for the supply of information between The Company and a User undertaking OTSDUW in order that planning and development of the National Electricity Transmission System can be co-ordinated.

Where the OTSUA also require works to be undertaken by any Relevant Transmission Licensee on its Transmission System The Company and the User shall throughout the construction and commissioning of such works:

(a) co-operate and assist each other in the development of co-ordinated construction programmes or any other planning or, in the case of The Company, analysis it undertakes in respect of the works; and

(b) provide to each other all information relating to, in the case of the User its own works and, in the case of The Company, the works on the Transmission Systems reasonably necessary to assist each other in the performance of that other’s part of the works, and shall use all reasonable endeavours to co-ordinate and integrate their respective part of the works; and

the User shall plan and develop the OTSUA, taking into account to the extent that it is reasonable and practicable to do so the reasonable requests of The Company relating to the planning and development of the National Electricity Transmission System.

Where The Company becomes aware that changes made to the investment plans of any Relevant Transmission Licensee may have a material effect on the OTSUA, The Company shall notify the User and provide the User with the necessary information about the relevant Transmission Systems sufficient for the User to assess the impact on the OTSUA.
APPENDIX A - PLANNING DATA REQUIREMENTS

PC.A.1 INTRODUCTION

The Appendix specifies data requirements to be submitted to The Company by Users, and in certain circumstances to Users by The Company.

PC.A.1.2 Submissions by Users

(a) Planning data submissions by Users shall be:

(i) with respect to each of the seven succeeding Financial Years (other than in the case of Registered Data which will reflect the current position and data relating to Demand forecasts which relates also to the current year);

(ii) provided by Users in connection with a CUSC Contract (PC.4.1, PC.4.4 and PC.4.5 refer);

(iii) provided by Users on a routine annual basis in calendar week 24 of each year to maintain an up-to-date data bank (although Network Operators may delay the submission of data (other than that to be submitted pursuant to PC.3.2(c) and PC.3.2(d)) until calendar week 28). In addition, the structural data in DRC Schedule 5 Tables 5(a), 5(b), 5(d), 5(e), 5(f) and DRC Schedule 13 (Lumped system susceptance (PC.A.2.3) only) provided by Network Operators by calendar week 28 shall be updated by calendar week 50 of each year (again which may be delayed as above until week 2 of the following calendar year). Where from the date of one annual (or in the case of Schedule 5 or Schedule 13 the calendar week 50) submission to another there is no change in the data (or in some of the data) to be submitted, instead of re-submitting the data, a User may submit a written statement that there has been no change from the data (or some of the data) submitted the previous time; and

(iv) provided by Network Operators in connection with Embedded Development (PC.4.4 refers).

(b) Where there is any change (or anticipated change) in Committed Project Planning Data or a significant change in Connected Planning Data in the category of Forecast Data or any change (or anticipated change) in Connected Planning Data in the categories of Registered Data or Estimated Registered Data supplied to The Company under the PC, notwithstanding that the change may subsequently be notified to The Company under the PC as part of the routine annual update of data (or that the change may be a Modification under the CUSC), the User shall, subject to PC.A.3.2.3 and PC.A.3.2.4, notify The Company in writing without delay.

(c) The notification of the change will be in the form required under this PC in relation to the supply of that data and will also contain the following information:

(i) the time and date at which the change became, or is expected to become, effective;

(ii) if the change is only temporary, an estimate of the time and date at which the data will revert to the previous registered form.

(d) The routine annual update of data, referred to in (a)(iii) above, need not be submitted in respect of Small Power Stations or Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System (except as provided in PC.3.2(c)), or unless specifically requested by The Company, or unless otherwise specifically provided.

PC.A.1.3 Submissions by The Company

Network Data release by The Company shall be:

(a) with respect to the current Financial Year;
(b) provided by The Company on a routine annual basis in calendar week 42 of each year. Where from the date of one annual submission to another there is no change in the data (or in some of the data) to be released, instead of repeating the data, The Company may release a written statement that there has been no change from the data (or some of the data) released the previous time.

The three parts of the Appendix

PC.A.1.4 The data requirements listed in this Appendix are subdivided into the following four parts:

(a) Standard Planning Data

This data (as listed in Part 1 of the Appendix) is first to be provided by a User at the time of an application for a CUSC Contract or in accordance with PC.4.4.3. It comprises data which is expected normally to be sufficient for The Company to investigate the impact on the National Electricity Transmission System of any User Development or Embedded Development associated with an application by the User for a CUSC Contract. Users should note that the term Standard Planning Data also includes the information referred to in PC.4.4.1.(a) and PC.4.4.3.(a). In the case of OTSUA, this data is first to be provided by a User in accordance with the time line in Appendix F.

(b) Detailed Planning Data

This data (as listed in Part 2 of the Appendix) includes both DPD-I and DPD-II and is to be provided in accordance with PC.4.4.2 and PC.4.4.4. It comprises additional, more detailed, data not normally expected to be required by The Company to investigate the impact on the National Electricity Transmission System of any User Development associated with an application by the User for a CUSC Contract or Embedded Development Agreement. Users and Network Operators in respect of Embedded Developments should note that the term Detailed Planning Data also includes Operation Diagrams and Site Common Drawings produced in accordance with the CC and ECC.

The User may, however, be required by The Company to provide the Detailed Planning Data in advance of the normal timescale before The Company can make an offer for a CUSC Contract, as explained in PC.4.5.

(c) Network Data

The data requirements for The Company in this Appendix are in Part 3.

(d) Offshore Transmission System (OTSDUW) Data

Generators who are undertaking OTSDUW are required to submit data in accordance with Appendix A as summarised in Schedule 18 of the Data Registration Code.

Forecast Data, Registered Data and Estimated Registered Data

PC.A.1.5 As explained in PC.5.4 and PC.5.5, Planning Data is divided into:

(i) those items of Standard Planning Data and Detailed Planning Data known as Forecast Data; and

(ii) those items of Standard Planning Data and Detailed Planning Data known as Registered Data; and

(iii) those items of Standard Planning Data and Detailed Planning Data known as Estimated Registered Data.

PC.A.1.6 The following paragraphs in this Appendix relate to Forecast Data:

3.2.2(b), (h), (i) and (j)

4.2.1

4.3.1

4.3.2
4.3.3
4.3.4
4.3.5
4.5
4.7.1
5.2.1
5.2.2
5.6.1

PC.A.1.7  The following paragraphs in this Appendix relate to Registered Data and Estimated Registered Data:

2.2.1
2.2.4
2.2.5
2.2.6
2.3.1
2.4.1
2.4.2
3.2.2(a), (c), (d), (e), (f), (g), (i)(part) and (j)
3.4.1
3.4.2
4.2.3
4.5(a)(i), (a)(iii), (b)(i) and (b)(iii)
4.6
5.3.2
5.4
5.4.2
5.4.3
5.5
5.6.3
6.2
6.3

PC.A.1.8  The data supplied under PC.A.3.3.1, although in the nature of Registered Data, is only supplied either upon application for a CUSC Contract, or in accordance with PC.4.4.3, and therefore does not fall to be Registered Data, but is Estimated Registered Data.

PC.A.1.9  Forecast Data must contain the User's best forecast of the data being forecast, acting as a reasonable and prudent User in all the circumstances.
PC.A.1.10 **Registered Data** must contain validated actual values, parameters or other information (as the case may be) which replace the estimated values, parameters or other information (as the case may be) which were given in relation to those data items when they were Preliminary Project Planning Data and Committed Project Planning Data, or in the case of changes, which replace earlier actual values, parameters or other information (as the case may be). Until amended pursuant to the Grid Code, these actual values, parameters or other information (as the case may be) will be the basis upon which the National Electricity Transmission System is planned, designed, built and operated in accordance with, amongst other things, the Transmission Licences, the STC and the Grid Code, and on which The Company therefore relies. In following the processes set out in the BC, The Company will use the data which has been supplied to it under the BC and the data supplied under OC2 in relation to Gensets, but the provision of such data will not alter the data supplied by Users under the PC, which may only be amended as provided in the PC.

PC.A.1.11 **Estimated Registered Data** must contain the User's best estimate of the values, parameters or other information (as the case may be), acting as a reasonable and prudent User in all the circumstances.

PC.A.1.12 Certain data does not need to be supplied in relation to Embedded Power Stations or Embedded DC Converter Stations or Embedded HVDC Systems where these are connected at a voltage level below the voltage level directly connected to the National Electricity Transmission System except in connection with a CUSC Contract, or unless specifically requested by The Company.

PC.A.1.13 In the case of OTSUA, Schedule 18 of the Data Registration Code shall be construed in such a manner as to achieve the intent of such provisions by reference to the OTSUA and the Interface Point and all Connection Points.
PC.A.2 USER’S SYSTEM (AND OTSUA) DATA

PC.A.2.1 Introduction

PC.A.2.1.1 Each User, whether connected directly via an existing Connection Point to the National Electricity Transmission System, or seeking such a direct connection, or providing terms for connection of an Offshore Transmission System to its User System to The Company, shall provide The Company with data on its User System (and any OTSUA) which relates to the Connection Site (and in the case of OTSUA, the Interface Point) and/or which may have a system effect on the performance of the National Electricity Transmission System. Such data, current and forecast, is specified in PC.A.2.2 to PC.A.2.5. In addition each Generator in respect of its Embedded Large Power Stations and its Embedded Medium Power Stations subject to a Bilateral Agreement and each Network Operator in respect of Embedded Medium Power Stations within its System not subject to a Bilateral Agreement connected to the Subtransmission System, shall provide The Company with fault infeed data as specified in PC.A.2.5.5 and each DC Converter owner with Embedded DC Converter Stations subject to a Bilateral Agreement and Embedded HVDC System Owner subject to a Bilateral Agreement, or Network Operator in the case of Embedded DC Converter Stations not subject to a Bilateral Agreement or Embedded HVDC Systems not subject to a Bilateral Agreement, connected to the Subtransmission System shall provide The Company with fault infeed data as specified in PC.A.2.5.6.

PC.A.2.1.2 Each User must reflect the system effect at the Connection Site(s) of any third party Embedded within its User System whether existing or proposed.

PC.A.2.1.3 Although not itemised here, each User with an existing or proposed Embedded Small Power Station, Embedded Medium Power Station, Embedded DC Converter Station or HVDC System with a Registered Capacity of less than 100MW or an Embedded installation of direct current converters which does not form a DC Converter Station or HVDC System in its User System may, at The Company’s reasonable discretion, be required to provide additional details relating to the User’s System between the Connection Site and the existing or proposed Embedded Small Power Station, Embedded Medium Power Station, Embedded DC Converter Station, Embedded HVDC System or Embedded installation of direct current converters which does not form a DC Converter Station or Embedded installation which does not form an HVDC System.

PC.A.2.1.4 At The Company’s reasonable request, additional data on the User’s System (or OTSUA) will need to be supplied. Some of the possible reasons for such a request, and the data required, are given in PC.A.6.2, PC.A.6.4, PC.A.6.5 and PC.A.6.6.

PC.A.2.2 User’s System (and OTSUA) Layout

PC.A.2.2.1 Each User shall provide a Single Line Diagram, depicting both its existing and proposed arrangement(s) of load current carrying Apparatus relating to both existing and proposed Connection Points (including in the case of OTSUA, Interface Points).

PC.A.2.2.2 The Single Line Diagram (three examples are shown in Appendix B) must include all parts of the User System operating at Supergrid Voltage throughout Great Britain and, in Scotland and Offshore, also all parts of the User System operating at 132kV or greater, and those parts of its Subtransmission System at any Transmission Site. In the case of OTSDUW, the Single Line Diagram must also include the OTSUA. In addition, the Single Line Diagram must include all parts of the User’s Subtransmission System (and any OTSUA) operating at a voltage greater than 50kV, and, in Scotland and Offshore, also all parts of the User’s Subtransmission System (and any OTSUA) operating at a voltage greater than 30kV, which, under either intact network or Planned Outage conditions:

(a) normally interconnects separate Connection Points, or busbars at a Connection Point which are normally run in separate sections; or
(b) connects Embedded Large Power Stations, or Embedded Medium Power Stations, or Embedded DC Converter Stations, or Embedded HVDC Systems or Offshore Transmission Systems connected to the User’s Subtransmission System, to a Connection Point or Interface Point.

At the User’s discretion, the Single Line Diagram can also contain additional details of the User’s Subtransmission System (and any OTSUA) not already included above, and also details of the transformers connecting the User’s Subtransmission System to a lower voltage. With The Company’s agreement, the Single Line Diagram can also contain information about the User’s System (and any OTSUA) at a voltage below the voltage of the Subtransmission System.

The Single Line Diagram for a Power Park Module (including DC Connected Power Park Modules) must include all parts of the System connecting generating equipment to the Grid Entry Point (or User System Entry Point if Embedded). As an alternative, the User may choose to submit a Single Line Diagram with the equipment between the equivalent Power Park Unit and the Common Collection Busbar reduced to an electrically equivalent network. The format for a Single Line Diagram for a Power Park Module (including DC Connected Power Park Modules) electrically equivalent system is shown in Appendix B.

The Single Line Diagram must include the points at which Demand data (provided under PC.A.4.3.4 and PC.A.4.3.5, or in the case of Generators, PC.A.5.) and fault infeed data (provided under PC.A.2.5) are supplied.

PC.A.2.2.3 The above-mentioned Single Line Diagram shall include:

(a) electrical circuitry (i.e. overhead lines, identifying which circuits are on the same towers, underground cables, power transformers, reactive compensation equipment and similar equipment); and

(b) substation names (in full or abbreviated form) with operating voltages.

In addition, for all load current carrying Apparatus operating at Supergrid Voltage throughout Great Britain and, in Scotland and Offshore, also at 132kV or greater, (and any OTSUA) the Single Line Diagram shall include:

(a) circuit breakers

(b) phasing arrangements.

PC.A.2.2.3.1 For the avoidance of doubt, the Single Line Diagram to be supplied is in addition to the Operation Diagram supplied pursuant to CC.7.4 or ECC.7.4.

PC.A.2.2.4 For each circuit shown on the Single Line Diagram provided under PC.A.2.2.1, each User shall provide the following details relating to that part of its User System and OTSUA:

Circuit Parameters:
Rated voltage (kV)
Operating voltage (kV)
Positive phase sequence reactance
Positive phase sequence resistance
Positive phase sequence susceptance
Zero phase sequence reactance (both self and mutual)
Zero phase sequence resistance (both self and mutual)
Zero phase sequence susceptance (both self and mutual)
In the case of a **Single Line Diagram** for a **Power Park Module** (including **DC Connected Power Park Modules**) electrically equivalent system the data should be on a 100MVA base. Depending on the equivalent system supplied an equivalent tap changer range may need to be supplied. Similarly mutual values, rated voltage and operating voltage may be inappropriate. Additionally in the case of **OTSUA**, seasonal maximum continuous ratings and circuit lengths are to be provided in addition to the data required under PC.A.2.2.4.

**PC.A.2.2.5** For each transformer shown on the **Single Line Diagram** provided under PC.A.2.2.1, each **User** (including those undertaking **OTSDUW**) shall provide the following details:

- Rated MVA
- Voltage Ratio
- Winding arrangement
- Positive sequence reactance (max, min and nominal tap)
- Positive sequence resistance (max, min and nominal tap)
- Zero sequence reactance

**PC.A.2.2.5.1.** In addition, for all interconnecting transformers between the **User's Supergrid Voltage System** and the **User's Subtransmission System** throughout **Great Britain** and, in **Scotland** and **Offshore**, also for all interconnecting transformers operating at 132kV or greater between the **User's System** and the **User's Subtransmission System** (and any **OTSUA**) the **User** shall supply the following information:-

- Tap changer range
- Tap change step size
- Tap changer type: on load or off circuit
- Earthing method: Direct, resistance or reactance
- Impedance (if not directly earthed)

**PC.A.2.2.6** Each **User** shall supply the following information about the **User's** equipment installed at a **Transmission Site** (or in the case of **OTSUA**, all **OTSDUW Plant and Apparatus**):-

(a) **Switchgear.** For all circuit breakers:-

- Rated voltage (kV)
- Operating voltage (kV)
- Rated 3-phase rms short-circuit breaking current, (kA)
- Rated 1-phase rms short-circuit breaking current, (kA)
- Rated 3-phase peak short-circuit making current, (kA)
- Rated 1-phase peak short-circuit making current, (kA)
- Rated rms continuous current (A)
- DC time constant applied at testing of asymmetrical breaking abilities (secs)

In the case of **OTSDUW Plant and Apparatus** operating times for circuit breaker, **Protection**, trip relay and total operating time should be provided.

(b) **Substation Infrastructure.** For the substation infrastructure (including, but not limited to, switch disconnectors, disconnectors, current transformers, line traps, busbars, through bushings, etc):-

- Rated 3-phase rms short-circuit withstand current (kA)
- Rated 1-phase rms short-circuit withstand current (kA)
- Rated 3-phase short-circuit peak withstand current (kA)
Rated 1-phase short-circuit peak withstand current (kA)
Rated duration of short circuit withstand (secs)
Rated rms continuous current (A)

A single value for the entire substation may be supplied, provided it represents the most restrictive item of current carrying apparatus.

PC.A.2.2.7 In the case of OTSUA the following should also be provided

(a) Automatic switching scheme schedules including diagrams and an explanation of how the System will operate and what plant will be affected by the schemes Operation.

(b) Intertripping schemes both Generation and Demand. In each case a diagram of the scheme and an explanation of how the System will operate and what Plant will be affected by the schemes Operation.

PC.A.2.3 Lumped System Susceptance

PC.A.2.3.1 For all parts of the User’s Subtransmission System (and any OTSUA) which are not included in the Single Line Diagram provided under PC.A.2.2.1, each User shall provide the equivalent lumped shunt susceptance at nominal Frequency.

PC.A.2.3.1.1 This should include shunt reactors connected to cables which are not normally in or out of service independent of the cable (ie. they are regarded as part of the cable).

PC.A.2.3.1.2 This should not include:

(a) independently switched reactive compensation equipment connected to the User’s System specified under PC.A.2.4, or;

(b) any susceptance of the User’s System inherent in the Demand (Reactive Power) data specified under PC.A.4.3.1.

PC.A.2.4 Reactive Compensation Equipment

PC.A.2.4.1 For all independently switched reactive compensation equipment (including any OTSUA), including that shown on the Single Line Diagram, not operated by The Company and connected to the User’s System at 132kV and above in England and Wales and 33kV and above in Scotland and Offshore (including any OTSDUW Plant and Apparatus operating at High Voltage), other than Power Factor correction equipment associated directly with Customers’ Plant and Apparatus, the following information is required:

(a) type of equipment (eg. fixed or variable);

(b) capacitive and/or inductive rating or its operating range in MVAr;

(c) details of any automatic control logic to enable operating characteristics to be determined;

(d) the point of connection to the User’s System (including OTSUA) in terms of electrical location and System voltage.

(e) In the case of OTSDUW Plant and Apparatus the User should also provide:-

(i) Connection node, voltage, rating, power loss, tap range and connection arrangement.

(ii) 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 where each time constant should be no less than 10ms.

(iii) For Static Var Compensation equipment the User should provide:

<table>
<thead>
<tr>
<th>HV Node</th>
<th>LV Node</th>
</tr>
</thead>
<tbody>
<tr>
<td>Control Node</td>
<td>Nominal Voltage</td>
</tr>
<tr>
<td></td>
<td>(kV)</td>
</tr>
<tr>
<td></td>
<td>Target Voltage</td>
</tr>
<tr>
<td></td>
<td>(kV)</td>
</tr>
</tbody>
</table>
Maximum MVAr at HV
Minimum MVAr at HV
Slope %
Voltage dependant Q Limit
Normal Running Mode
Positive and zero phase sequence resistance and reactance
Transformer winding type
Connection arrangements

PC.A.2.4.2 DC Converter Station owners, HVDC System Owners (and a User where the OTSUA includes an OTSDUW DC Converter) are also required to provide information about the reactive compensation and harmonic filtering equipment required to ensure that their Plant and Apparatus (and the OTSUA) complies with the criteria set out in CC.6.1.5 or ECC.6.1.5 (as applicable).

PC.A.2.5 Short Circuit Contribution to National Electricity Transmission System

PC.A.2.5.1 General

(a) To allow The Company to calculate fault currents, each User is required to provide data, calculated in accordance with Good Industry Practice, as set out in the following paragraphs of PC.A.2.5.

(b) The data should be provided for the User's System with all Generating Units (including Synchronous Generating Units), Power Park Units, HVDC Systems and DC Converters Synchronised to that User's System (and any OTSUA where appropriate). The User must ensure that the pre-fault network conditions reflect a credible System operating arrangement.

(c) The list of data items required, in whole or part, under the following provisions, is set out in PC.A.2.5.6. Each of the relevant following provisions identifies which data items in the list are required for the situation with which that provision deals.

The fault currents in sub-paragraphs (a) and (b) of the data list in PC.A.2.5.6 should be based on an a.c. load flow that takes into account any pre-fault current flow across the Point of Connection (and in the case of OTSUA, Interface Points and Connection Points) being considered.

Measurements made under appropriate System conditions may be used by the User to obtain the relevant data.

(d) The Company may at any time, in writing, specifically request for data to be provided for an alternative System condition, for example minimum plant, and the User will, insofar as such request is reasonable, provide the information as soon as reasonably practicable following the request.

PC.A.2.5.2 Network Operators and Non-Embedded Customers are required to submit data in accordance with PC.A.2.5.4. Generators, DC Converter Station owners, HVDC System Owners and Network Operators, in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems within such Network Operator's Systems are required to submit data in accordance with PC.A.2.5.5.

PC.A.2.5.3 Where prospective short-circuit currents on Transmission equipment are close to the equipment rating, and in The Company’s reasonable opinion more accurate calculations of the prospective short circuit currents are required, then The Company will request additional data as outlined in PC.A.6.6 below.

PC.A.2.5.4 Data from Network Operators and Non-Embedded Customers
PC.A.2.5.4.1 Data is required to be provided at each node on the Single Line Diagram provided under PC.A.2.2.1 at which motor loads and/or Embedded Small Power Stations and/or Embedded Medium Power Stations and/or Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System are connected, assuming a fault at that location, as follows:

The data items listed under the following parts of PC.A.2.5.6:-

(a) (i), (ii), (iii), (iv), (v) and (vi);

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c) - (f).

PC.A.2.5.4.2 Network Operators shall provide the following data items in respect of each Interface Point within their User System:

(a) Maximum Export Capacity;
(b) Maximum Import Capacity; and,
(c) Interface Point Target Voltage/Power Factor

Network Operators shall alongside these parameters include details of any manual or automatic post fault actions to be taken by the owner/operator of the Offshore Transmission System connected to such Interface Point that are required by the Network Operator.

PC.A.2.5.5 Data from Generators (including Generators undertaking OTSDUW and those responsible for DC Connected Power Park Modules), DC Converter Station owners, HVDC System Owners and from Network Operators in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems within such Network Operator's Systems.

PC.A.2.5.5.1 For each Generating Unit (including Synchronous Generating Units forming part of a Synchronous Power Generating Module) with one or more associated Unit Transformers, the Generator, or the Network Operator in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems within such Network Operator's System is required to provide values for the contribution of the Power Station Auxiliaries (including Auxiliary Gas Turbines or Auxiliary Diesel Engines) to the fault current flowing through the Unit Transformer(s).

The data items listed under the following parts of PC.A.2.5.6(a) should be provided:-

(i), (ii) and (v);

(iii) if the associated Generating Unit (including Synchronous Generating Units forming part of a Synchronous Power Generating Module) step-up transformer can supply zero phase sequence current from the Generating Unit side to the National Electricity Transmission System;

(iv) if the value is not 1.0 p.u;

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c) - (f), and with the following parts of this PC.A.2.5.5.

PC.A.2.5.5.2 Auxiliary motor short circuit current contribution and any Auxiliary Gas Turbine Unit contribution through the Unit Transformers must be represented as a combined short circuit current contribution at the Generating Unit's (including Synchronous Generating Units forming part of a Synchronous Power Generating Module) terminals, assuming a fault at that location.

PC.A.2.5.5.3 If the Power Station or HVDC System or DC Converter Station (or OTSDUW Plant and Apparatus which provides a fault infeed) has separate Station Transformers, data should be provided for the fault current contribution from each transformer at its high voltage terminals, assuming a fault at that location, as follows:-
The data items listed under the following parts of PC.A.2.5.6

(a) (i), (ii), (iii), (iv), (v) and (vi);

and the data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(b) - (f).

PC.A.2.5.5.4 Data for the fault infeeds through both Unit Transformers and Station Transformers shall be provided for the normal running arrangement when the maximum number of Generating Units (including Synchronous Generating Units forming part of a Synchronous Power Generating Module) are Synchronised to the System or when all the DC Converters at a DC Converter Station or HVDC Converters within an HVDC System are transferring Rated MW in either direction. Where there is an alternative running arrangement (or transfer in the case of a DC Converter Station or HVDC System) which can give a higher fault infeed through the Station Transformers, then a separate data submission representing this condition shall be made.

PC.A.2.5.5.5 Unless the normal operating arrangement within the Power Station is to have the Station and Unit Boards interconnected within the Power Station, no account should be taken of the interconnection between the Station Board and the Unit Board.

PC.A.2.5.5.6 Auxiliary motor short circuit current contribution and any auxiliary DC Converter Station contribution or HVDC System contribution through the Station Transformers must be represented as a combined short circuit current contribution through the Station Transformers.

PC.A.2.5.5.7 Where a Manufacturer’s Data & Performance Report exists in respect of the model of the Power Park Unit, the User may opt to reference the Manufacturer’s Data & Performance Report as an alternative to the provision of data in accordance with this PC.A.2.5.5.7. For the avoidance of doubt, all other data provision pursuant to the Grid Code shall still be provided including a Single Line Diagram and those data pertaining thereto.

For each Power Park Module (including DC Connected Power Park Modules) and each type of Power Park Unit (e.g. a Doubly Fed Induction Generator) (and any OTSDUW Plant and Apparatus which provides a fault infeed), including any Auxiliaries, positive, negative and zero sequence root mean square current values are to be provided of the contribution to the short circuit current flowing at:

(i) the Power Park Unit terminals, 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

(ii) the Grid Entry Point (and in case of OTSUA, Transmission Interface Point), or User System Entry Point if Embedded

for the following solid faults at the Grid Entry Point (and in case of OTSUA, Interface Point), or User System Entry Point if Embedded:

(i) a symmetrical three phase short circuit

(ii) a single phase to earth short circuit

(iii) a phase to phase short circuit

(iv) a two phase to earth short circuit

For a Power Park Module (including DC Connected Power Park Modules) in which one or more of the Power Park Units utilise a protective control such as a crowbar circuit, the data should indicate whether the protective control will act in each of the above cases and the effects of its action shall be included in the data. For any case in which the protective control will act, the data for the fault shall also be submitted for the limiting case in which the protective circuit will not act, which may involve the application of a non-solid fault, and the positive, negative and zero sequence retained voltages at:

(i) the Power Park Unit terminals, or the Common Collection Busbar if an equivalent Single Line Diagram and associated data is provided and

(ii) the Grid Entry Point, or User System Entry Point if Embedded
in this limiting case shall be provided.

For each fault for which data is submitted, the data items listed under the following parts of PC.A.2.5.6(a) shall be provided:-

(iv), (vii), (viii), (ix), (x);

In addition, if an equivalent Single Line Diagram has been provided the data items listed under the following parts of PC.A.2.5.6(a) shall be provided:-

(xi), (xii), (xiii);

In addition, for a Power Park Module (including DC Connected Power Park Modules) in which one or more of the Power Park Units utilise a protective control such as a crowbar circuit:-

the data items listed under the following parts of PC.A.2.5.6(a) shall be provided:-

(xiv), (xv);

All of the above data items shall be provided in accordance with the detailed provisions of PC.A.2.5.6(c), (d), (f).

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

PC.A.2.5.6 Data Items

(a) The following is the list of data utilised in this part of the PC. It also contains rules on the data which generally apply:-

(i) Root mean square of the symmetrical three-phase short circuit current infeed at the instant of fault, \( I_1^* \);

(ii) Root mean square of the symmetrical three-phase short circuit current after the subtransient fault current contribution has substantially decayed, \( I_1' \);

(iii) the zero sequence source resistance and reactance values of the User’s System as seen from the node on the Single Line Diagram provided under PC.A.2.2.1 (or Power Generating Module or Station Transformer high voltage terminals or Generating Unit terminals or DC Converter terminals or HVDC System terminals, as appropriate) consistent with the infeed described in PC.A.2.5.1.(b);

(iv) root mean square of the pre-fault voltage at which the maximum fault currents were calculated;

(v) the positive sequence X/R ratio at the instant of fault;

(vi) the negative sequence resistance and reactance values of the User’s System seen from the node on the Single Line Diagram provided under PC.A.2.2.1 (or Power Generating Module or Station Transformer high voltage terminals, or Generating Unit terminals or DC Converter terminals or HVDC System terminals as appropriate) if substantially different from the values of positive sequence resistance and reactance which would be derived from the data provided above;

(vii) A continuous trace and a table showing the root mean square of the positive, negative and zero sequence components of the short circuit current between zero and 140ms at 10ms intervals;
(viii) The **Active Power** (or **Interface Point Capacity**) being exported pre-fault by the **OTSDUW Plant and Apparatus**) being generated pre-fault by the **Power Park Module** (including **DC Connected Power Park Modules**) and by each type of **Power Park Unit**;

(ix) The reactive compensation shown explicitly on the **Single Line Diagram** that is switched in;

(x) The **Power Factor** of the **Power Park Module** (including **DC Connected Power Park Modules**) and of each **Power Park Unit** type;

(xi) The positive sequence X/R ratio of the equivalent at the **Common Collection Busbar** or **Interface Point** in the case of **OTSUA**;

(xii) The minimum zero sequence impedance of the equivalent seen from the **Common Collection Busbar** or **Interface Point** in the case of **OTSUA**;

(xiii) The number of **Power Park Units** represented in the equivalent **Power Park Unit**;

(xiv) The additional rotor resistance and reactance (if any) that is applied to the **Power Park Unit** under a fault condition;

(xv) A continuous trace and a table showing the root mean square of the positive, negative and zero sequence components of the retained voltage at the fault point and **Power Park Unit** terminals, or the **Common Collection Busbar** if an equivalent **Single Line Diagram** and associated data as described in **PC.A.2.2.2** is provided or **Interface Point** in the case of **OTSUA**, representing the limiting case, which may involve the application of a non-solid fault, required to not cause operation of the protective control;

(b) In considering this data, unless the **User** notifies **The Company** accordingly at the time of data submission, **The Company** will assume that the time constant of decay of the subtransient fault current corresponding to the change from **I₀** to **I₀'**, (T") is not significantly different from 40ms. If that assumption is not correct in relation to an item of data, the **User** must inform **The Company** at the time of submission of the data.

(c) The value for the X/R ratio must reflect the rate of decay of the d.c. component that may be present in the fault current and hence that of the sources of the initial fault current. All shunt elements and loads must therefore be deleted from any system model before the X/R ratio is calculated.

(d) In producing the data, the **User** may use "time step analysis" or "fixed-point-in-time analysis" with different impedances.

(e) If a fixed-point-in-time analysis with different impedances method is used, then in relation to the data submitted under (a) (i) above, the data will be required for "time zero" to give **I₀". The figure of 120ms is consistent with a decay time constant T" of 40ms, and if that figure is different, then the figure of 120ms must be changed accordingly.

(f) Where a "time step analysis" is carried out, the X/R ratio may be calculated directly from the rate of decay of the d.c. component. The X/R ratio is not that given by the phase angle of the fault current if this is based on a system calculation with shunt loads, but from the Thévenin equivalent of the system impedance at the instant of fault with all non-source shunts removed.
PC.A.3.1.1 Each Generator, HVDC System Owner and DC Converter Station owner (and a User where the OTSUA includes an OTSDUW DC Converter) with an existing, or proposed, Power Station or DC Converter Station or HVDC System directly connected, or to be directly connected, to the National Electricity Transmission System (or in the case of OTSUA, the Interface Point), shall provide The Company with data relating to that Power Station or DC Converter Station or HVDC System, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4.

Embedded

PC.A.3.1.2(a) Each Generator, HVDC System Owner and DC Converter Station owner in respect of its existing, and/or proposed, Embedded Large Power Stations and/or Embedded HVDC Systems and/or Embedded DC Converter Stations and/or its Embedded Medium Power Stations subject to a Bilateral Agreement and each Network Operator in respect of its Embedded Medium Power Stations not subject to a Bilateral Agreement and/or Embedded DC Converter Stations not subject to a Bilateral Agreement and/or Embedded HVDC Systems not subject to a Bilateral Agreement within such Network Operator’s System in each case connected to the Subtransmission System, shall provide The Company with data relating to that Power Station or DC Converter Station or HVDC System, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4.

(b) No data need be supplied in relation to any Small Power Station or any Medium Power Station or installations of direct current converters which do not form a DC Converter Station or HVDC System, connected at a voltage level below the voltage level of the Subtransmission System except:-

(i) in connection with an application for, or under, a CUSC Contract, or
(ii) unless specifically requested by The Company under PC.A.3.1.4.

PC.A.3.1.3 (a) Each Network Operator shall provide The Company with the data specified in PC.A.3.2.2(c)(i) and (ii) and PC.A.3.2.2(i).

(b) Network Operators need not submit planning data in respect of an Embedded Small Power Station unless required to do so under PC.A.1.2(b) or unless specifically requested under PC.A.3.1.4 below, in which case they will supply such data.

PC.A.3.1.4 (a) PC.A.4.2.4(b) and PC.A.4.3.2(a) explain that the forecast Demand submitted by each Network Operator must be net of the output of all Small Power Stations and Medium Power Stations and Customer Generating Plant and all installations of direct current converters which do not form a DC Converter Station or HVDC System, Embedded within that Network Operator’s System. The Network Operator must inform The Company of:

(i) the number of such Embedded Power Stations and such Embedded installations of direct current converters (including the number of Generating Units or Power Park Modules (including DC Connected Power Park Modules) or DC Converters or HVDC Systems) together with their summated capacity; and

(ii) beginning from the 2015 Week 24 data submission, for each Embedded Small Power Station of registered capacity (as defined in the Distribution Code) of 1MW or more:

1. A reference which is unique to each Network Operator;
2. The production type as follows:
   a) In the case of an Embedded Small Power Station first connected on or after 1 January 2015, the production type must be selected from the list below:
      - 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 or
- Other;

Together with a statement as to whether the generation forms part of a CHP scheme;

(iii) beginning from the 2019 Week 24 data submission, for Embedded Power Stations with Registered Capacity of less than 1MW, their best estimate of the aggregated capacity of all such Embedded Power Stations per production type as defined in the list in PC.A.3.1.4 (a)(ii)(2)(a).

b) In the case of an Embedded Small Power Station first connected to the Users’ System before 1 January 2015, as an alternative to the production type, the technology type(s) used, selected from the list set out at paragraph 2.23 in Version 2 of the Regulatory Instructions and Guidance relating to the distributed generation incentive, innovation funding incentive and registered power zones, reference 83/07, published by Ofgem in April 2007;

c) In the case of an Embedded Small Power Station comprising Electricity Storage Modules or Electricity Storage Units first connected the User’s System on or after May 2020, the storage type must be selected from the list below:

- Chemical
  - Ammonia
  - Hydrogen
  - Synthetic Fuels
  - Drop-in Fuels
  - Methanol
  - Synthetic Natural Gas

- Electrical
  - Supercapacitors
  - Superconducting Magnetic ES (SMES)

- Mechanical
  - Adiabatic Compressed Air
  - Diabatic Compressed Air
  - Liquid Air Energy Storage

Pumped Hydro
Flywheels
- Thermal
  - Latent Heat Storage
  - Thermochemical Storage
  - Sensible Heat Storage
- Electrochemical
  - Classic Batteries
    - Lead Acid
    - Lithium Polymer (Li-Polymer)
    - Metal Air
    - Nickle Cadmium (Ni-Cd)
    - Sodium Nickle Chloride (Na-NiCl₂)
    - Lithium Ion (Li–ion)
    - Sodium Ion (Na–ion)
    - Lithium Sulphur (Li-S)
    - Sodium Sulphur (Na-S)
    - Nickle –Metal Hydride (Ni-MH)
  - Flow Batteries
    - Vanadium Red-Oxide
    - Zinc – Iron (Zn –Fe)
    - Zinc – Bromine (Zn –Br)
  - Other

- Together with a statement as to whether the storage forms part of a CHP scheme. Where this information is not held by the Network Operator it should provide its best view of the type of storage technology.

3. The registered capacity (as defined in the Distribution Code) in MW;

4. The lowest voltage level node that is specified on the most up-to-date Single Line Diagram to which it connects or where it will export most of its power;

5. Where it generates electricity from wind or PV, the geographical location using either latitude or longitude or grid reference coordinates of the primary or higher voltage substation to which it connects;

6. The reactive power and voltage control mode, including the voltage set-point and reactive range, where it operates in voltage control mode, or the target Power Factor, where it operates in Power Factor mode;

7. Details of the types of loss of mains Protection in place and their relay settings which in the case of Embedded Small Power Stations and Embedded Medium Power Stations and Customer Generating Plant and Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4. Such requirement would arise where The Company reasonably considers that the collective effect of a number of such Embedded Power Stations and Customer Generating Plants and Embedded installations of direct current converters may have a significant system effect on the National Electricity Transmission System.

(b) On receipt of this data, the Network Operator or Generator (if the data relates to Power Stations referred to in PC.A.3.1.2) may be further required, at The Company's reasonable discretion, to provide details of Embedded Small Power Stations and Embedded Medium Power Stations and Customer Generating Plant and Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System, both current and forecast, as specified in PC.A.3.2 to PC.A.3.4. Such requirement would arise where The Company reasonably considers that the collective effect of a number of such Embedded Power Stations and Customer Generating Plants and Embedded installations of direct current converters may have a significant system effect on the National Electricity Transmission System.

Busbar Arrangements
Where Generating Units, which term includes CCGT Units and Synchronous Generating Units within a Synchronous Power Generating Module and Power Park Modules (including DC Connected Power Park Modules), and DC Converters, and HVDC Systems are connected to the National Electricity Transmission System via a busbar arrangement which is or is expected to be operated in separate sections, the section of busbar to which each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module), DC Converter, HVDC System or Power Park Module (including DC Connected Power Park Modules) is connected is to be identified in the submission.

**Output Data**

**PC.A.3.2**

(a) **Large Power Stations and Gensets**

Data items PC.A.3.2.2 (a), (b), (c), (d), (e), (f) and (h) are required with respect to each Large Power Station and each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module) and Power Park Module (including DC Connected Power Park Modules) of each Large Power Station and for each Genset (although (a) is not required for CCGT Units and (b), (d) and (e) are not normally required for CCGT Units and (a), (b), (c), (d), (e), (f) and (h) are not normally required for Power Park Units).

(b) **Embedded Small Power Stations and Embedded Medium Power Stations**

Data item PC.A.3.2.2 (a) is required with respect to each Embedded Small Power Station and Embedded Medium Power Station and each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module) and Power Park Module (including DC Connected Power Park Modules) of each Embedded Small Power Station and Embedded Medium Power Station (although (a) is not required for CCGT Units or Power Park Units). In addition, data item PC.A.3.2.2(c)(ii) is required with respect to each Embedded Medium Power Station.

(c) **CCGT Units/Modules**

(i) Data item PC.A.3.2.2 (g) is required with respect to each CCGT Unit;

(ii) data item PC.A.3.2.2 (a) is required with respect to each CCGT Module; and

(iii) data items PC.A.3.2.2 (b), (c), (d) and (e) are required with respect to each CCGT Module unless The Company informs the relevant User in advance of the submission that it needs the data items with respect to each CCGT Unit for particular studies, in which case it must be supplied on a CCGT Unit basis.

Where any definition utilised or referred to in relation to any of the data items does not reflect CCGT Units, such definition shall be deemed to relate to CCGT Units for the purposes of these data items. Any Schedule in the DRC which refers to these data items shall be interpreted to incorporate the CCGT Unit basis where appropriate;

(d) **Cascade Hydro Schemes**

Data item PC.A.3.2.2(i) is required with respect to each Cascade Hydro Scheme.

(e) **Power Park Units/Modules**

Data items PC.A.3.2.2 (k) is required with respect to each Power Park Module (including DC Connected Power Park Modules).

(f) **DC Converters and HVDC Systems**

Data items PC.A.3.2.2 (a), (b), (c), (d) (e) (f) (h) and (i) are required with respect of each HVDC System, each DC Converter Station and each DC Converter in each DC Converter Station. For installations of direct current converters which do not form a DC Converter Station only data item PC.A.3.2.2.(a) is required.
Items (a), (b), (d), (e), (f), (g), (h), (i), (j) and (k) are to be supplied by each Generator, DC Converter Station owner, HVDC System Owner or Network Operator (as the case may be) in accordance with PC.A.3.1.1, PC.A.3.1.2, PC.A.3.1.3 and PC.A.3.1.4. Items (a), and (f)-(v) are to be supplied (as applicable) by a User in the case of OTSUA which includes an OTSDUW DC Converter. Item (c) is to be supplied by each Network Operator in all cases:-

(a) Registered Capacity (MW), Maximum Capacity (in the case of Power Generating Modules in addition to Registered Capacity on a Power Station basis) or Interface Point Capacity in the case of OTSDUW;

(b) Output Usable (MW) on a monthly basis;

(c) (i) System Constrained Capacity (MW) ie. any constraint placed on the capacity of the Embedded Generating Unit (including a Synchronous Generating Unit within a Synchronous Power Generating Module), Embedded Power Park Module (including DC Connected Power Park Modules) an Offshore Transmission System at an Interface Point, Embedded HVDC System or DC Converter at an Embedded DC Converter Station due to the Network Operator's System in which it is Embedded. Where Generating Units (which term includes CCGT Units and Synchronous Generating Units within a Synchronous Power Generating Module), Power Park Modules (including DC Connected Power Park Modules), Offshore Transmission Systems at an Interface Point, HVDC Systems or DC Converters are connected to a Network Operator's User System via a busbar arrangement which is or is expected to be operated in separate sections, details of busbar running arrangements and connected circuits at the substation to which the Embedded Generating Unit (including Synchronous Generating Units within an Embedded Synchronous Power Generating Module), Embedded Power Park Module (including DC Connected Power Park Modules), Offshore Transmission System at an Interface Point, or Embedded HVDC System or Embedded DC Converter is connected sufficient for The Company to determine where the MW generated by each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module), Power Park Module (including DC Connected Power Park Modules), HVDC System or DC Converter at that Power Station or DC Converter Station or Offshore Transmission System at an Interface Point would appear onto the National Electricity Transmission System;

(ii) any Reactive Despatch Network Restrictions;

(d) Minimum Generation (MW), and in the case of Power Generating Modules only Minimum Stable Operating Level (MW) and Minimum Regulating Level;

(e) MW obtainable from Generating Units (including Synchronous Generating Units within a Synchronous Power Generating Module), Power Park Modules (including DC Connected Power Park Modules), HVDC Systems or DC Converters at a DC Converter Station in excess of Registered Capacity or Maximum Capacity;

(f) Generator Performance Chart:

(i) GB Code User(s) in respect of Generating Units shall provide a Generator Performance Chart and EU Code Users in respect of Power Generating Modules shall provide a Power Generating Module Performance Chart and a Synchronous Generating Unit Performance Chart.

(ii) at the electrical point of connection to the Offshore Transmission System for an Offshore Synchronous Generating Unit and Offshore Synchronous Power Generating Module.

(iii) at the electrical point of connection to the National Electricity Transmission System (or User System if Embedded) for a Non Synchronous Generating Unit (excluding a Power Park Unit), Power Park Module (including DC Connected Power Park Modules), HVDC System and DC Converter at a DC Converter Station;

(iv) at the Interface Point for OTSDUW Plant and Apparatus
Where a **Reactive Despatch Network Restriction** applies, its existence and details should be highlighted on the **Generator Performance Chart**, in sufficient detail for **The Company** to determine the nature of the restriction.

(g) a list of the **CCGT Units** within a **CCGT Module**, identifying each **CCGT Unit**, and the **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, together:-

(i) (in the case of a **Range CCGT Module** connected to the **National Electricity Transmission System**) with details of the single **Grid Entry Point** (there can only be one) at which power is provided from the **Range CCGT Module**;

(ii) (in the case of an **Embedded Range CCGT Module**) with details of the single **User System Entry Point** (there can only be one) at which power is provided from the **Range CCGT Module**;

Provided that, nothing in this sub-paragraph (g) shall prevent the busbar at the relevant point being operated in separate sections;

(h) expected running regime(s) at each **Power Station**, **HVDC System** or **DC Converter Station** and type of **Power Generating Module** or **Generating Unit** (as applicable), eg. **Steam Unit**, **Gas Turbine Unit**, **Combined Cycle Gas Turbine Unit**, **Power Park Module** (including **DC Connected Power Park Modules**), **Novel Units** (specify by type), etc;

(i) a list of **Power Stations** and **Generating Units** within a **Cascade Hydro Scheme**, identifying each **Generating Unit** (including **Synchronous Generating Units** within a **Synchronous Power Generating Module**) and **Power Station** and the **Cascade Hydro Scheme** of which each form part unambiguously. In addition:

(i) details of the **Grid Entry Point** at which **Active Power** is provided, or if **Embedded** the **Grid Supply Point(s)** within which the **Generating Unit** (including **Synchronous Generating Units** within a **Synchronous Power Generating Module**) is connected;

(ii) where the **Active Power** output of a **Generating Unit** is split between more than one **Grid Supply Points** the percentage that would appear under normal and outage conditions at each **Grid Supply Point**.

(j) The following additional items are only applicable to **DC Converters** at **DC Converter Stations** and **HVDC Systems**.

- **Registered Import Capacity** (MW);
- **Import Usable** (MW) on a monthly basis;
- **Minimum Import Capacity** (MW);
- MW that may be absorbed by a **DC Converter** or **HVDC System** in excess of **Registered Import Capacity** and **Maximum HVDC Active Power Transmission Capacity** under importing conditions and the duration for which this is available;

(k) the number and types of the **Power Park Units** within a **Power Park Module** (including **DC Connected Power Park Modules**), identifying each **Power Park Unit**, the **Power Park Module** of which it forms part and identifying the **BM Unit** of which each **Power Park Module** forms part, unambiguously. In the case of a **Power Station** directly connected to the **National Electricity Transmission System** with multiple **Power Park Modules** (including **DC Connected Power Park Modules**) where **Power Park Units** can be selected to run in different **Power Park Modules** and/or **Power Park Modules** can be selected to run in different **BM Units**, details of the possible configurations should also be submitted. In addition, for **Offshore Power Park Modules** (including **DC Connected Power Park Modules**), the number of **Offshore Power Park Strings** that are aggregated into one **Offshore Power Park Module** should also be submitted.
the number and types of the **Synchronous Generating Units** within a **Synchronous Power Generating Module**, identifying each **Synchronous Generating Unit**, the **Synchronous Power Generating Module** of which it forms part and identifying the **BM Unit** of which each **Synchronous Power Generating Module** forms part, unambiguously. In the case of a **Power Station** directly connected to the **National Electricity Transmission System** with multiple **Synchronous Power Generating Modules** where **Synchronous Generating Units** can be selected to run in different **Synchronous Power Generating Modules** and/or **Synchronous Power Generating Modules** can be selected to run in different **BM Units**, details of the possible configurations should also be submitted.

**PC.A.3.2.3** Notwithstanding any other provision of this PC, the **CCGT Units** within a **CCGT Module**, details of which are required under paragraph (g) of PC.A.3.2.2, can only be amended in accordance with the following provisions:-

(a) 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) if the **CCGT Module** is a **Range CCGT Module**, the **CCGT Units** within that **CCGT Module** and the **Grid Entry Point** at which the power is provided can only be amended as described in BC1.A1.6.4.

**PC.A.3.2.4** Notwithstanding any other provision of this PC, the **Power Park Units** within a **Power Park Module** (including **DC Connected Power Park Modules**), and the **Power Park Modules** (including **DC Connected Power Park Modules**) within a **BM Unit**, details of which are required under paragraph (k) of PC.A.3.2.2, can only be amended in accordance with the following provisions:-

(a) if the **Power Park Units** within that **Power Park Module** can only be amended such that the **Power Park Module** comprises different **Power Park Units** due to repair/replacement of individual **Power Park Units** if The Company gives its prior consent in writing. Notice of the wish to amend a **Power Park Unit** within such a **Power Park Module** (including **DC Connected Power Park Modules**) must be given at least 4 weeks before it is wished for the amendment to take effect;

(b) if the **Power Park Units** within that **Power Park Module** (including **DC Connected Power Park Modules**) and/or the **Power Park Modules** (including **DC Connected Power Park Modules**) within that **BM Unit** can be selected to run in different **Power Park Modules** and/or **BM Units** as an alternative operational running arrangement the **Power Park Units** within the **Power Park Module**, the **BM Unit** of which each **Power Park Module** forms part, and the **Grid Entry Point** at which the power is provided can only be amended as described in BC1.A.1.8.4.

**PC.A.3.2.5** Notwithstanding any other provision of this PC, the **Synchronous Generating Units** within a **Synchronous Power Generating Module**, and the **Synchronous Power Generating Modules** within a **BM Unit**, details of which are required under paragraph (l) of PC.A.3.2.2, can only be amended in accordance with the following provisions:-

(a) if the **Synchronous Generating Units** within that **Synchronous Power Generating Module** can only be amended such that the **Synchronous Power Generating Module** comprises different **Synchronous Generating Units** due to repair/replacement of individual **Synchronous Generating Units** if The Company gives its prior consent in writing. Notice of the wish to amend a **Synchronous Generating Unit** within such a **Synchronous Power Generating Module** must be given at least 4 weeks before it is wished for the amendment to take effect;
(b) if the Synchronous Generating Units within that Synchronous Power Generating Module and/or the Synchronous Power Generating Modules within that BM Unit can be selected to run in different Synchronous Power Generating Modules and/or BM Units as an alternative operational running arrangement the Synchronous Generating Units within the Synchronous Power Generating Module, the BM Unit of which each Synchronous Power Generating Module forms part, and the Grid Entry Point at which the power is provided can only be amended as described in BC1.A.1.9.4(c). The requirements of PC.A.3.2.5 need not be satisfied if Generators have already submitted data in respect of PC.A.3.2.3, PC.A.3.2.4 and PC.A.3.2.5 for the same Power Generating Module.

PC.A.3.3. Rated Parameters Data

PC.A.3.3.1 The following information is required to facilitate an early assessment, by The Company, of the need for more detailed studies;

(a) for all Generating Units (excluding Power Park Units) and Power Park Modules (including DC Connected Power Park Modules):
   - Rated MVA
   - Rated MW;

(b) for each Synchronous Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module):
   - Short circuit ratio
   - Direct axis transient reactance;
   - Inertia constant (for whole machine), MWsecs/MVA;

(c) for each Synchronous Generating Unit step-up transformer (including the step up transformer of a Synchronous Generating Unit within a Synchronous Power Generating Module):
   - Rated MVA
   - Positive sequence reactance (at max, min and nominal tap);

(d) for each DC Converter at a DC Converter Station, HVDC System, DC Converter connecting a Power Park Module (including a DC Connected Power Park Module) and Transmission DC Converter (forming part of an OTSUA), DC Converter or HVDC Converter type (e.g. current/voltage sourced)
   - Rated MW per pole for import and export
   - Number of poles and pole arrangement
   - Rated DC voltage/pole (kV)
   - Return path arrangement
   - Remote AC connection arrangement (excluding OTSDUW DC Converters)
   - Maximum HVDC Active Power Transmission Capacity
   - Minimum Active Power Transmission Capacity

(e) for each type of Power Park Unit in a Power Park Module not connected to the Total System by a DC Converter or HVDC System:
   - Rated MVA
   - Rated MW
   - Rated terminal voltage
   - Inertia constant, (MWsec/MVA)

Additionally, for Power Park Units that are squirrel-cage or doubly-fed induction
generators driven by wind turbines:

- Stator reactance.
- Magnetising reactance.
- Rotor resistance (at rated running)
- Rotor reactance (at rated running)

The generator rotor speed range (minimum and maximum speeds in RPM) (for doubly-fed induction generators only)

Converter MVA rating (for doubly-fed induction generators only)

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.

This information should only be given in the data supplied in accordance with PC.4.4 and PC.4.5.

**PC.A.3.4**

**General Generating Unit, Power Park Module (including DC Connected Power Park Modules), Power Generating Module, HVDC System and DC Converter Data**

**PC.A.3.4.1** The point of connection to the **National Electricity Transmission System** or the **Total System**, if other than to the **National Electricity Transmission System**, in terms of geographical and electrical location and system voltage is also required.

**PC.A.3.4.2**

(a) **Type of Generating Unit** (i.e. Synchronous Power Generating Unit within a Power Generating Module, Synchronous Generating Unit, Non-Synchronous Generating Unit, DC Converter, Power Park Module (including DC Connected Power Park Modules) or HVDC System).

(b) In the case of a **Synchronous Generating Unit** (including Synchronous Generating Units within a Synchronous Power Generating Module) details of the Exciter category, for example whether it is a rotating **Exciter** or a static **Exciter** or in the case of a **Non-Synchronous Generating Unit** the voltage control system.

(c) **Whether a Power System Stabiliser** is fitted.

**PC.A.3.4.3** Each **Generator** shall supply **The Company** with the production type(s) used as the primary source of power in respect of each **Generating Unit** (including Synchronous Generating Units within a Synchronous Power Generating Module), selected from the list set out below:

- 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
In the case of an Electricity Storage Module or Electricity Storage Unit, each Generator shall supply The Company with the production type(s) used as the primary Electricity Storage source (including Synchronous Electricity Storage Units within a Synchronous Electricity Storage Module), selected from the list set out below:

- Chemical
  - Ammonia
  - Hydrogen
  - Synthetic Fuels
  - Drop-in Fuels
  - Methanol
  - Synthetic Natural Gas
- Electrical
  - Supercapacitors
  - Superconducting Magnetic ES (SMES)
- Mechanical
  - Adiabatic Compressed Air
  - Diabatic Compressed Air
  - Liquid Air Energy Storage
  - Pumped Hydro
  - Flywheels
- Thermal
  - Latent Heat Storage
  - Thermochemical Storage
  - Sensible Heat Storage
- Electrochemical
  - Classic Batteries
  - Lead Acid
  - Lithium Polymer (Li-Polymer)
  - Metal Air
  - Nickle Cadmium (Ni-Cd)
  - Sodium Nickle Chloride (Na-NiCl₂)
  - Lithium Ion (Li–ion)
  - Sodium Ion (Na–ion)
  - Lithium Sulphur (Li–S)
  - Sodium Sulphur(Na-S)
  - Nickle –Metal Hydride (Ni-MH)
  - Flow Batteries
    - Vanadium Red-Oxide
    - Zinc – Iron (Zn–Fe)
    - Zinc – Bromine (Zn–Br)
  - Other

PC.A.4 DEMAND AND ACTIVE ENERGY DATA

PC.A.4.1 Introduction

PC.A.4.1.1 Each User directly connected to the National Electricity Transmission System with Demand shall provide The Company with the Demand data, historic, current and forecast, as specified in PC.A.4.2 and PC.A.4.3. Paragraphs PC.A.4.1.2 and PC.A.4.1.3 apply equally to Active Energy requirements as to Demand unless the context otherwise requires.
Data will need to be supplied by:

(a) each Network Operator, in relation to Demand and Active Energy requirements on its User System;

(b) each Non-Embedded Customer, Pumped Storage Generators (with respect to Pumping Demand) and Generators in relation to Electricity Storage Modules in relation to their Demand and Active Energy requirements.

(c) each DC Converter Station owner or HVDC System Owner in relation to Demand and Active Energy transferred (imported) to its DC Converter Station or HVDC System.

(d) each OTSDUW DC Converter in relation to the Demand at each Interface Point and Connection Point.

Demand of Power Stations directly connected to the National Electricity Transmission System is to be supplied by the Generator under PC.A.5.2.

References in this PC to data being supplied on a half hourly basis refer to it being supplied for each period of 30 minutes ending on the hour or half-hour in each hour.

Access Periods and Access Groups

Each Connection Point must belong to one, and only one, Access Group.

Each Transmission Interface Circuit must have an Access Period.

The Access Period shall

(a) normally be a minimum of 8 continuous weeks and can occur in any one of three maintenance years during the period from calendar week 13 to calendar week 43 (inclusive) in each year; or,

(b) exceptionally and provided that agreement is reached between The Company and the relevant User(s), such agreement to be sought in accordance with PC.7, the Access Period may be of a period not less than 4 continuous weeks and can occur in any one of three maintenance years during the period from calendar week 10 to calendar week 43 (inclusive) in each year.

The Company shall submit in writing no later than calendar week 6 in each year:

(a) the calendar weeks defining the proposed start and finish of each Access Period for each Transmission Interface Circuit; and

(b) the Connection Points in each Access Group.

The submission by The Company under PC.A.4.1.4.4 (a) above shall commence in 2010 and shall then continue each year thereafter. The submission by The Company under PC.A.4.1.4.4 (b) shall commence in 2009 and then continue each year thereafter.

It is permitted for Access Periods to overlap in the same Access Group and in the same maintenance year. However, where possible Access Periods will be sought by The Company that do not overlap with any other Access Period within that Access Group for each maintenance year. Where it is not possible to avoid overlapping Access Periods, The Company will indicate to Users by calendar week 6 its initial view of which Transmission Interface Circuits will need to be considered out of service concurrently for the purpose of assessing compliance to Licence Standards. The obligation on The Company to indicate which Transmission Interface Circuits will need to be considered out of service concurrently for the purpose of assessing compliance to Licence Standards shall commence in 2010 and shall continue each year thereafter.

Following the submission(s) by The Company by week 6 in each year and where required by either party, both The Company and the relevant User(s) shall use their reasonable endeavours to agree the appropriate Access Group(s) and Access Period for each Transmission Interface Circuit prior to week 17 in each year. The requirement on The Company and the relevant User(s) to agree, shall commence in respect of Access Groups only in 2010. This paragraph PC.A.4.1.4.6 shall apply in its entirety in 2011 and shall then continue each year thereafter.
In exceptional circumstances, and with the agreement of all parties concerned, where a **Connection Point** is specified for the purpose of the **Planning Code** as electrically independent **Subtransmission Systems**, then data submissions can be on the basis of two (or more) individual **Connection Points**.

**User's User System Demand (Active Power) and Active Energy Data**

**PC.A.4.2.1** Forecast daily **Demand (Active Power)** profiles, as specified in (a), (b) and (c) below, in respect of each of the **User's User Systems** (each summated over all **Grid Supply Points** in each **User System**) are required for:

(a) peak day on each of the **User's User Systems** (as determined by the **User** giving the numerical value of the maximum **Demand (Active Power)** that in the **Users'** opinion could reasonably be imposed on the **National Electricity Transmission System**;

(b) day of peak **National Electricity Transmission System Demand (Active Power)** as notified by **The Company** pursuant to PC.A.4.2.2;

(c) day of minimum **National Electricity Transmission System Demand (Active Power)** as notified by **The Company** pursuant to PC.A.4.2.2.

In addition, the total **Demand (Active Power)** in respect of the time of peak **National Electricity Transmission System Demand** in the preceding **Financial Year** in respect of each of the **User's User Systems** (each summated over all **Grid Supply Points** in each **User System**) both outturn and weather corrected shall be supplied.

**PC.A.4.2.2** No later than calendar week 17 each year, **The Company** shall notify each **Network Operator** and **Non-Embedded Customer** in writing of the following, for the current **Financial Year** and for each of the following seven **Financial Years**, which will, until replaced by the following year’s notification, be regarded as the relevant specified days and times under PC.A.4.2.1:

(a) the date and time of the annual peak of the **National Electricity Transmission System Demand**;

(b) the date and time of the annual minimum of the **National Electricity Transmission System Demand**;

(c) the relevant **Access Period** for each **Transmission Interface Circuit**; and,

(d) concurrent **Access Periods** of two or more **Transmission Interface Circuits** (if any) that are situated in the same **Access Group**.

The submissions by **The Company** made under PC.A.4.2.1 (c) and PC.A.4.2.1 (d) above shall commence in 2010 and shall continue in respect of each year thereafter.

**PC.A.4.2.3** The total **Active Energy** used on each of the **Network Operators’ or Non-Embedded Customers’ User Systems** (each summated over all **Grid Supply Points** in each **User System**) in the preceding **Financial Year**, both outturn and weather corrected, together with a prediction for the current financial year, is required. Each **Active Energy** submission shall be subdivided into the following categories of **Customer** tariff:

- LV1
- LV2
- LV3
- HV
- EHV
- Traction
- Lighting

In addition, the total **User System** losses and the **Active Energy** provided by **Embedded Small Power Stations** and **Embedded Medium Power Stations** shall be supplied.

**PC.A.4.2.4** All forecast **Demand (Active Power)** and **Active Energy** specified in PC.A.4.2.1 and PC.A.4.2.3 shall:
(a) in the case of PC.A.4.2.1(a), (b) and (c), be such that the profiles comprise average Active Power levels in 'MW' for each time marked half hour throughout the day;

(b) in the case of PC.A.4.2.1(a), (b) and (c), be that remaining after any deductions reasonably considered appropriate by the User to take account of the output profile of all Embedded Small Power Stations and Embedded Medium Power Stations and Customer Generating Plant and imports across Embedded External Interconnections including imports across Embedded installations of direct current converters which do not form a DC Converter Station or HVDC System and Embedded DC Converter Stations and Embedded HVDC Systems with a Registered Capacity or HVDC Active Power Transmission Capacity of less than 100MW;

(c) be based upon Annual ACS Conditions for times that occur during week 44 through to week 12 (inclusive) and based on Average Conditions for weeks 13 to 43 (inclusive).

PC.A.4.3 Connection Point Demand (Active and Reactive Power)

PC.A.4.3.1 Forecast Demand (Active Power) and Power Factor (values of the Power Factor at maximum and minimum continuous excitation may be given instead where more than 95% of the total Demand at a Connection Point is taken by synchronous motors) to be met at each Connection Point within each Access Group is required for:

(a) the time of the maximum Demand (Active Power) at the Connection Point (as determined by the User) that in the User's opinion could reasonably be imposed on the National Electricity Transmission System;

(b) the time of peak National Electricity Transmission System Demand as provided by The Company under PC.A.4.2.2;

(c) the time of minimum National Electricity Transmission System Demand as provided by The Company under PC.A.4.2.2;

(d) the time of the maximum Demand (Apparent Power) at the Connection Point (as determined by the User) during the Access Period of each Transmission Interface Circuit;

(e) at a time specified by either The Company or a User insofar as such a request is reasonable.

Instead of such forecast Demand to be met at each Connection Point within each Access Group the User may (subject to PC.A.4.3.4) submit such Demand at each node on the Single Line Diagram.

In addition, the Demand in respect of each of the time periods referred to in PC.A.4.3.1 (a) to (e) in the preceding Financial Year in respect of each Connection Point within each Access Group both outturn and weather corrected shall be supplied. The "weather correction" shall normalise outturn figures to Annual ACS Conditions for times that occur during calendar week 44 through to calendar week 12 (inclusive) or Average Conditions for the period calendar weeks 13 to calendar week 43 (inclusive) and shall be performed by the relevant User on a best endeavours basis.

The submission by a User pursuant to PC.A.4.3.1 (d) shall commence in 2011 and shall then continue each year thereafter.

PC.A.4.3.2 All forecast Demand specified in PC.A.4.3.1 shall:

(a) be that remaining after any deductions reasonably considered appropriate by the User to take account of the output of all Embedded Small Power Stations and Embedded Medium Power Stations and Customer Generating Plant and imports across Embedded External Interconnections, including Embedded installations of direct current converters which do not form a DC Converter Station, HVDC System and Embedded DC Converter Stations and Embedded HVDC Systems and such deductions should be separately stated;

(b) include any User's System series reactive losses but exclude any reactive compensation equipment specified in PC.A.2.4 and exclude any network susceptance specified in PC.A.2.3;
(c) be based upon Annual ACS Conditions for times that occur during calendar week 44 through to calendar week 12 (inclusive) and based on Average Conditions for calendar weeks 13 to calendar week 43 (inclusive), both corrections being made on a best endeavours basis;

(d) reflect the User’s opinion of what could reasonably be imposed on the National Electricity Transmission System.

PC.A.4.3.3 The date and time of the forecast maximum Demand (Apparent Power) at the Connection Point as specified in PC.A.4.3.1 (a) and (d) is required.

PC.A.4.3.4 Each Single Line Diagram provided under PC.A.2.2.2 shall include the Demand (Active Power) and Power Factor (values of the Power Factor at maximum and minimum continuous excitation may be given instead where more than 95% of the Demand is taken by synchronous motors) at the time of the peak National Electricity Transmission System Demand (as provided under PC.A.4.2.2) at each node on the Single Line Diagram. These Demands shall be consistent with those provided under PC.A.4.3.1(b) above for the relevant year.

PC.A.4.3.5 The Single Line Diagram must represent the User’s User System layout under the period specified in PC.A.4.3.1(b) (at the time of peak National Electricity Transmission System Demand). Should the User’s User System layout during the other times specified in PC.A.4.3.1 be planned to be materially different from the Single Line Diagram submitted to The Company pursuant to PC.A.2.2.1 the User shall in respect of such other times submit:

(i) an alternative Single Line Diagram that accurately reflects the revised layout and in such case shall also include appropriate associated data representing the relevant changes, or;

(ii) submit an accurate and unambiguous description of the changes to the Single Line Diagram previously submitted for the time of peak National Electricity Transmission System Demand.

Where a User does not submit any changes, The Company will assume that the Single Line Diagram (and associated circuit and node data) provided at the time of peak National Electricity Transmission System Demand will be valid for all other times. In respect of such other times, where the User does not submit such nodal demands at the times defined in PC.A.4.3.1(a), (c), (d) and (e), the nodal demands will be pro-rata, to be consistent with the submitted Connection Point Demands.

PC.A.4.4 The Company will assemble and derive in a reasonable manner, the forecast information supplied to it under PC.A.4.2.1, PC.A.4.3.1, PC.A.4.3.4 and PC.A.4.3.5 above into a cohesive forecast and will use this in preparing Forecast Demand information in the Seven Year Statement and for use in The Company’s Operational Planning. If any User believes that the cohesive forecast Demand information in the Seven Year Statement does not reflect its assumptions on Demand, it should contact The Company to explain its concerns and may require The Company, on reasonable request, to discuss these forecasts. In the absence of such expressions, The Company will assume that Users concur with The Company’s cohesive forecast.

PC.A.4.5 Post Fault User System Layout

PC.A.4.5.1 Where for the purposes of The Company assessing against the Licence Standards an Access Group, the User reasonably considers it appropriate that revised post fault User System layouts should be taken into account by The Company, the following information is required to be submitted by the User:

(i) the specified Connection Point assessment period (PC.A.4.3.1,(a)-(e)) that is being evaluated;

(ii) an accurate and unambiguous description of the Transmission Interface Circuits considered to be switched out due to a fault;

(iii) appropriate revised Single Line Diagrams and/or associated revised nodal Demand and circuit data detailing the revised User System(s) conditions;
(iv) where the User’s planned post fault action consists of more than one component, each component must be explicitly identified using the Single Line Diagram and associated nodal Demand and circuit data;

(v) the arrangements for undertaking actions (eg the time taken, automatic or manual and any other appropriate information);

The User must not submit any action that it does not have the capability or the intention to implement during the assessment period specified (subject to there being no further unplanned outages on the User’s User System).

PC.A.4.6 Control of Demand or Reduction of Pumping Load Offered as Reserve

| Magnitude of Demand or pumping load or Electricity Storage Module charging load which is tripped | MW |
| 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 |

PC.A.4.7 General Demand Data

PC.A.4.7.1 The following information is infrequently required and should be supplied (wherever possible) when requested by The Company:

(a) details of any individual loads (including (as applicable) the load behaviour of an Electricity Storage Module when operating in a mode analogous to demand) which have characteristics significantly different from the typical range of Domestic, Commercial, Electricity Storage or Industrial loads supplied;

(b) the sensitivity of the Demand (Active and Reactive Power) to variations in voltage and Frequency on the National Electricity Transmission System at the time of the peak Demand (Active Power). The sensitivity factors quoted for the Demand (Reactive Power) should relate to that given under PC.A.4.3.1 and, therefore, include any User’s System series reactive losses but exclude any reactive compensation equipment specified in PC.A.2.4 and exclude any network susceptance specified in PC.A.2.3;

(c) details of any traction loads, e.g. connection phase pairs and continuous load variation with time;

(d) the average and maximum phase unbalance, in magnitude and phase angle, which the User would expect its Demand to impose on the National Electricity Transmission System;

(e) the maximum harmonic content which the User would expect its Demand to impose on the National Electricity Transmission System;

(f) details of all loads which may cause Demand fluctuations greater than those permitted under Engineering Recommendation P28 Issue 2, Stage 1 at a Point of Common Coupling including the Flicker Severity Short Term and the Flicker Severity Long Term.

(g) In the case of Electricity Storage Modules, details of the Maximum Capacity, Maximum Import Power, Registered Import Capability, charge time, discharge time and operating periods.
PC.A.5 POWER GENERATING MODULE, GENERATING UNIT, POWER PARK MODULE (INCLUDING DC CONNECTED POWER PARK MODULES), DC CONVERTER, HVDC EQUIPMENT AND OTSDUW PLANT AND APPARATUS DATA

PC.A.5.1 Introduction

Directly Connected

PC.A.5.1.1 Each Generator (including those undertaking OTSDUW), with existing or proposed Power Stations directly connected, or to be directly connected, to the National Electricity Transmission System, shall provide The Company with data relating to that Plant and Apparatus, both current and forecast, as specified in PC.A.5.2, PC.A.5.3, PC.A.5.4 and PC.A.5.7 as applicable.

Each DC Converter Station owner or HVDC System Owner, with existing or proposed DC Converter Stations or HVDC Systems (including Generators undertaking OTSDUW which includes an OTSDUW DC Converter) directly connected, or to be directly connected, to the National Electricity Transmission System, shall provide The Company with data relating to that Plant and Apparatus, both current and forecast, as specified in PC.A.5.2 and PC.A.5.4.

GB Generators, DC Converter Station owners, EU Generators and HVDC System Owners shall ensure that the models supplied in respect of their Plant and Apparatus provide a true and accurate behaviour of the plant as built as required under PC.A.5.3.2(c), PC.A.5.4.2(a) and PC.A.5.4.3 and verified through the Compliance Processes (CP) or European Compliance Processes (ECP) as applicable.

Embedded

PC.A.5.2 Each Generator, in respect of its existing, or proposed, Embedded Large Power Stations and its Embedded Medium Power Stations subject to a Bilateral Agreement and each Network Operator in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement within its System shall provide The Company with data relating to each of those Large Power Stations and Medium Power Stations, both current and forecast, as specified in PC.A.5.2, PC.A.5.3, PC.A.5.4 and PC.A.5.7 as applicable.

Each DC Converter Station owner or HVDC System Owner, or Network Operator in the case of an Embedded DC Converter Station or Embedded HVDC System not subject to a Bilateral Agreement within its System with existing or proposed HVDC Systems or DC Converter Stations shall provide The Company with data relating to each of those HVDC Systems or DC Converter Stations, both current and forecast, as specified in PC.A.5.2 and PC.A.5.4.

However, no data need be supplied in relation to those Embedded Medium Power Stations or Embedded DC Converter Stations or Embedded HVDC Systems if they are connected at a voltage level below the voltage level of the Subtransmission System except in connection with an application for, or under a, CUSC Contract or unless specifically requested by The Company under PC.A.5.1.4.

GB Generators, DC Converter Station owners, EU Generators and HVDC System Owners shall ensure that the models supplied in respect of their Plant and Apparatus provide a true and accurate behaviour of the plant as built as required under PC.A.5.3.2(c), PC.A.5.4.2(a) and PC.A.5.4.3 and verified through the Compliance Processes (CP) or European Compliance Processes (ECP) as applicable.

PC.A.5.3 Each Network Operator need not submit Planning Data in respect of Embedded Small Power Stations unless required to do so under PC.A.1.2(b), PC.A.3.1.4 or unless specifically requested under PC.A.5.1.4 below, in which case they will supply such data.
PC.A.5.1.4 PC.A.4.2.4(b) and PC.A.4.3.2(a) explained that the forecast Demand submitted by each Network Operator must be net of the output of all Medium Power Stations and Small Power Stations and Customer Generating Plant Embedded within that User’s System. In such cases, the Network Operator must provide The Company with the relevant information specified under PC.A.3.1.4. On receipt of this data further details may be required at The Company’s discretion as follows:

(i) in the case of details required from the Network Operator for Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement and Embedded Small Power Stations and Embedded DC Converters and Embedded HVDC Systems in each case within such Network Operator’s System and Customer Generating Plant; and

(ii) in the case of details required from the Generator of Embedded Large Power Stations and Embedded Medium Power Stations subject to a Bilateral Agreement; and

(iii) in the case of details required from the DC Converter Station owner of an Embedded DC Converter or DC Converter Station or HVDC System Owner of an Embedded HVDC System Subject to a Bilateral Agreement.

both current and forecast, as specified in PC.A.5.2 and PC.A.5.3. Such requirement would arise when The Company reasonably considers that the collective effect of a number of such Embedded Small Power Stations, Embedded Medium Power Stations, Embedded DC Converter Stations, Embedded HVDC Systems, DC Converters and Customer Generating Plants may have a significant system effect on the National Electricity Transmission System.

PC.A.5.1.5 DPD I and DPD II

The Detailed Planning Data described in this Part 2 of the Appendix comprises both DPD I and DPD II. The required data is listed and collated in the Data Registration Code. The Users need to refer to the DRC to establish whether data referred to here is DPD I or DPD II.

PC.A.5.2 Demand

PC.A.5.2.1 For each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module) which has an associated Unit Transformer, the value of the Demand supplied through this Unit Transformer when the Generating Unit is at Rated MW output is to be provided.

PC.A.5.2.2 Where the Power Station or DC Converter Station or HVDC System has associated Demand additional to the unit-supplied Demand of PC.A.5.2.1 which is supplied from either the National Electricity Transmission System or the Generator’s User System the Generator, DC Converter Station owner, HVDC System Owner or the Network Operator (in the case of Embedded Medium Power Stations not subject to a Bilateral Agreement within its System), as the case may be, shall supply forecasts for each Power Station or DC Converter Station or HVDC System of:

(a) the maximum Demand that, in the User’s opinion, could reasonably be imposed on the National Electricity Transmission System or the Generator’s User System as appropriate;

(b) the Demand at the time of the peak National Electricity Transmission System Demand

(c) the Demand at the time of minimum National Electricity Transmission System Demand.
PC.A.5.2.3  No later than calendar week 17 each year The Company shall notify each Generator in respect of its Large Power Stations and its Medium Power Stations and each DC Converter owner in respect of its DC Converter Station and each HVDC System Owner in respect of its HVDC System subject to a Bilateral Agreement and each Network Operator in respect of each Embedded Medium Power Station not subject to a Bilateral Agreement and each Embedded DC Converter Station or Embedded HVDC System not subject to a Bilateral Agreement within such Network Operator’s System in writing of the following, for the current Financial Year and for each of the following seven Financial Years, which will be regarded as the relevant specified days and times under PC.A.5.2.2:

(a) the date and time of the annual peak of the National Electricity Transmission System Demand at Annual ACS Conditions;

(b) the date and time of the annual minimum of the National Electricity Transmission System Demand at Average Conditions.

PC.A.5.2.4  At its discretion, The Company may also request further details of the Demand as specified in PC.A.4.6

PC.A.5.2.5  In the case of OTSDUW Plant and Apparatus the following data shall be supplied:

(a) The maximum Demand that could occur at the Interface Point and each Connection Point (in MW and MVar);

(b) Demand at specified time of annual peak half hour of National Electricity Transmission System Demand at Annual ACS Conditions (in MW and MVar); and

(c) Demand at specified time of annual minimum half-hour of National Electricity Transmission System Demand (in MW and MVar).

For the avoidance of doubt, Demand data associated with Generators undertaking OTSDUW which utilise an OTSDUW DC Converter should supply data under PC.A.4.

PC.A.5.3  Synchronous Power Generating Modules, Synchronous Generating Unit and Associated Control System Data

PC.A.5.3.1  The data submitted below are not intended to constrain any Ancillary Services Agreement

PC.A.5.3.2  The following Synchronous Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module) and Power Station data should be supplied:

(a) Synchronous Generating Unit Parameters

   Rated terminal volts (kV)
   Maximum terminal voltage set point (kV)

   Terminal voltage set point step resolution – if not continuous (kV)
   * Rated MVA
   * Rated MW
   * Minimum Generation MW
   * Short circuit ratio
     Direct axis synchronous reactance
   * Direct axis transient reactance
     Direct axis sub-transient reactance
     Direct axis short-circuit sub-transient time constant
     Direct axis short-circuit transient time constant
     Quadrature axis synchronous reactance
     Quadrature axis sub-transient reactance
Quadrature axis short-circuit sub-transient time constant.
Stator time constant
Stator leakage reactance
Armature winding direct-current resistance

Note: The above data item relating to armature winding direct-current resistance need only be supplied with respect to Generating Units commissioned after 1st March 1996 and in cases where, for whatever reason, the Generator or the Network Operator, as the case may be is aware of the value of the relevant parameter.

* Turbogenerator inertia constant (MWsec/MVA)
Rated field current (amps) at Rated MW and MVAr output and at rated terminal voltage.
Field current (amps) open circuit saturation curve for Generating Unit terminal voltages ranging from 50% to 120% of rated value in 10% steps as derived from appropriate manufacturers test certificates.

(b) Parameters for Generating Unit Step-up Transformers

* Rated MVA
  Voltage ratio
  Positive sequence reactance (at max, min, & nominal tap)
  Positive sequence resistance (at max, min, & nominal tap)
  Zero phase sequence reactance
  Tap changer range
  Tap changer step size
  Tap changer type: on load or off circuit

(c) Excitation Control System parameters

Note: The data items requested under Option 1 below may continue to be provided in relation to Generating Units connected to the System at 09 January 1995 (in this paragraph, the "relevant date") or the new data items set out under Option 2 may be provided. Generators or Network Operators, as the case may be, must supply the data as set out under Option 2 (and not those under Option 1) for Generating Unit excitation control systems commissioned after the relevant date, those Generating Unit excitation control systems recommissioned for any reason such as refurbishment after the relevant date and Generating Unit excitation control systems where, as a result of testing or other process, the Generator or Network Operator, as the case may be, is aware of the data items listed under Option 2 in relation to that Generating Unit.

Option 1

DC gain of Excitation Loop
Rated field voltage
Maximum field voltage
Minimum field voltage
Maximum rate of change of field voltage (rising)
Maximum rate of change of field voltage (falling)
Details of Excitation Loop described in block diagram form showing transfer functions of individual elements.
Dynamic characteristics of Over-excitation Limiter
Dynamic characteristics of Under-excitation Limiter

Option 2

Excitation System Nominal Response
Rated Field Voltage
No-Load Field Voltage
Excitation System On-Load Positive Ceiling Voltage
Excitation System No-Load Positive Ceiling Voltage
Excitation System No-Load Negative Ceiling Voltage

Stator Current Limiter (applicable only to Synchronous Power Generating Modules)

Details of Excitation System (including PSS if fitted) described in block diagram form showing transfer functions of individual elements.

Details of Over-excitation Limiter described in block diagram form showing transfer functions of individual elements.

Details of Under-excitation Limiter described in block diagram form showing transfer functions of individual elements.

The block diagrams submitted after 1 January 2009 in respect of the Excitation System (including the Over-excitation Limiter and the Under-excitation Limiter) for Generating Units with a Completion date after 1 January 2009 or subject to a Modification to the Excitation System after 1 January 2009, should have been verified as far as reasonably practicable by simulation studies as representing the expected behaviour of the system.

(d) Governor Parameters

Incremental Droop values (in %) are required for each Generating Unit at six MW loading points (MLP1 to MLP6) as detailed in PC.A.5.5.1 (this data item needs only be provided for Large Power Stations).

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 09 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 governor control systems commissioned after the relevant date, those Generating Unit governor control systems recommissioned for any reason such as refurbishment after the relevant date and 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. EU Generators are also required to submit the data as set out in option 2. Additional data required from EU Generators which own or operate Type C or Type D Power Generating Modules are marked in brackets with an asterisk (eg (*)). For the avoidance of doubt, items marked as (*) need not be supplied by GB Generators.

Option 1

(i) Governor Parameters (for Reheat Steam Units)

HP governor average gain MW/Hz
Speeder motor setting range
HP governor valve time constant
HP governor valve opening limits
HP governor valve rate limits
Reheater time constant (Active Energy stored in re heater)
IP governor average gain MW/Hz
IP governor setting range
IP governor valve time constant
IP governor valve opening limits
IP governor valve rate limits

Details of acceleration sensitive elements in HP & IP governor loop.
A governor block diagram showing transfer functions of individual elements.

(ii) Governor Parameters (for Non-Reheat Steam Units and Gas Turbine Units)
  Governor average gain
  Speeder motor setting range
  Time constant of steam or fuel governor valve
  Governor valve opening limits
  Governor valve rate limits
  Time constant of turbine
  Governor block diagram

The following data items need only be supplied for Large Power Stations:

(iii) Boiler & Steam Turbine Data
  Boiler Time Constant (Stored Active Energy) s
  HP turbine response ratio:
    proportion of Primary Response arising from HP turbine %
  HP turbine response ratio:
    proportion of High Frequency Response arising from HP turbine %

[End of Option 1]

Option 2

(i) Governor and associated prime mover Parameters - All Generating Units (including Synchronous Generating Units within a Synchronous Power Generating Module)
  Governor Block Diagram showing transfer function of individual elements including acceleration sensitive elements.
  Governor Time Constant (in seconds)
  Speeder Motor Setting Range (%)
  Average Gain (MW/Hz)

Governor Deadband need only be provided for Large Power Stations owned and operated by GB Generators (and both Frequency Response Deadband and Frequency Response Insensitivity should be supplied in respect of Type C and D Power Generating Modules within Large Power Stations and Medium Power Stations excluding Embedded Medium Power Stations not subject to a Bilateral Agreement") owned and operated by EU Code Generators.
Where the *Generating Unit* governor does not have a selectable *Governor Deadband* (or *Frequency Response Deadband* and *Frequency Response Insensitivity*)* facility as specified above, then the actual value of the *Governor Deadband* or (*Frequency Response Deadband* and *Frequency Response Insensitivity*)* need only be provided.

The block diagrams submitted after 1 January 2009 in respect of the governor system for *Generating Units* with a *Completion date* after 1 January 2009 or subject to a *Modification* to the governor system after 1 January 2009, should have been verified as far as reasonably practicable by simulation studies as representing the expected behaviour of the system.

(ii) **Governor and associated prime mover Parameters - Steam Units**

- HP Valve Time Constant (in seconds)
- HP Valve Opening Limits (%)
- HP Valve Opening Rate Limits (%/second)
- HP Valve Closing Rate Limits (%/second)
- HP Turbine Time Constant (in seconds)

- IP Valve Time Constant (in seconds)
- IP Valve Opening Limits (%)
- IP Valve Opening Rate Limits (%/second)
- IP Valve Closing Rate Limits (%/second)
- IP Turbine Time Constant (in seconds)

- LP Valve Time Constant (in seconds)
- LP Valve Opening Limits (%)
- LP Valve Opening Rate Limits (%/second)
- LP Valve Closing Rate Limits (%/second)
- LP Turbine Time Constant (in seconds)
- Reheater Time Constant (in seconds)
- Boiler Time Constant (in seconds)
- HP Power Fraction (%)
- IP Power Fraction (%)

(iii) **Governor and associated prime mover Parameters - Gas Turbine Units**

- Inlet Guide Vane Time Constant (in seconds)
- Inlet Guide Vane Opening Limits (%)
- Inlet Guide Vane Opening Rate Limits (%/second)
- Inlet Guide Vane Closing Rate Limits (%/second)
- Fuel Valve Constant (in seconds)
- Fuel Valve Opening Limits (%)

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Fuel Valve Opening Rate Limits (%/second)
Fuel Valve Closing Rate Limits (%/second)
Waste Heat Recovery Boiler Time Constant (in seconds)

(iv) Governor and associated prime mover Parameters - Hydro Generating Units
Guide Vane Actuator Time Constant (in seconds)
Guide Vane Opening Limits (%)
Guide Vane Opening Rate Limits (%/second)
Guide Vane Closing Rate Limits (%/second)
Water Time Constant (in seconds)

(v) Governor Parameters – Synchronous Electricity Storage Units
For **Synchronous Electricity Storage Modules** which are derived from compressed air energy storage systems, the following data should be provided. For other **Synchronous Electricity Storage Modules**, data should be supplied as required by **The Company** in accordance with PC.A.7
Valve Actuator Time Constant (in seconds)
Valve Opening Limits (%)
Valve Opening Rate Limits (%/second)
Valve Closing Rate Limits (%/second)

[End of Option 2]

(e) Unit Control Options
The following data items need only be supplied with respect to **Large Power Stations**:
Maximum **Droop** %
Normal **Droop** %
Minimum **Droop** %
Maximum **Governor Deadband** or (maximum **Frequency Response Deadband** and maximum **Frequency Response Insensitivity***) ±Hz
Normal **Governor Deadband** or (normal **Frequency Response Deadband** and normal **Frequency Response Insensitivity***) ±Hz
Minimum **Governor Deadband** or (minimum **Frequency Response Deadband** and minimum **Frequency Response Insensitivity***) ±Hz
Maximum output **Governor Deadband** (or maximum output **Frequency Response Deadband** and maximum **Frequency Response Insensitivity***) ±MW
Normal output **Governor Deadband** (or normal output **Frequency Response Deadband** and normal output **Frequency Response Insensitivity***) ±MW
Minimum output **Governor Deadband** (or minimum output **Frequency Response Deadband** and minimum output **Frequency Response Insensitivity***) ±MW

**Frequency** settings between which Unit Load Controller **Droop** applies:
- Maximum Hz
- Normal Hz
- Minimum Hz

State if sustained response is normally selected.
(f) Plant Flexibility Performance

The following data items need only be supplied with respect to Large Power Stations, and should be provided with respect to each Genset:

# Run-up rate to Registered Capacity,
# Run-down rate from Registered Capacity,
# Synchronising Generation,
   Regulating range
   Load rejection capability while still Synchronised and able to supply Load.

Data items marked with a hash (#) should be applicable to a Genset which has been Shutdown for 48 hours.

* Data items marked with an asterisk are already requested under partx1, PC.A.3.3.1, to facilitate an early assessment by The Company as to whether detailed stability studies will be required before an offer of terms for a CUSC Contract can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.

(g) Generating Unit Mechanical Parameters

It is occasionally necessary for The Company to assess the interaction between the Total System and the mechanical components of Generating Units. For Generating Units (including Synchronous Generating Units within a Synchronous Power Generating Module) with a Completion Date on or after 01 April 2015, the following data items should be supplied:

- The number of turbine generator masses.
- Diagram showing the Inertia and parameters for each turbine generator mass (kgm²) and Stiffness constants and parameters between each turbine generator mass for the complete drive train (Nm/rad).
- Number of poles.
- Relative power applied to different parts of the turbine (%).
- Torsional mode frequencies (Hz).
- Modal damping decrement factors for the different mechanical modes.

PC.A.5.4 Power Park Module, Non-Synchronous Generating Unit and Associated Control System Data

PC.A.5.4.1 The data submitted below are not intended to constrain any Ancillary Services Agreement

PC.A.5.4.2 The following Power Park Unit, Power Park Module and Power Station data should be supplied in the case of a Power Park Module not connected to the Total System by a DC Converter or HVDC System (and in the case of PC.A.5.4.2(f) any OTSUA):

Where a Manufacturer’s Data & Performance Report exists in respect of the model of the Power Park Unit, the User may subject to The Company’s agreement, opt to reference the Manufacturer’s Data & Performance Report as an alternative to the provision of data in accordance with PC.A.5.4.2 except for:

(1) the section marked thus # at sub paragraph (b); and
(2) all of the harmonic and flicker parameters required under sub paragraph (h); and

(3) all of the site specific model parameters relating to the voltage or frequency control systems required under sub paragraphs (d) and (e),

which must be provided by the User in addition to the Manufacturer’s Data & Performance Report reference.

(a) Power Park Unit model

A mathematical model of each type of Power Park Unit (including Electricity Storage Units) capable of representing its transient and dynamic behaviour under both small and large disturbance conditions. The model shall include non-linear effects and represent all equipment relevant to the dynamic performance of the Power Park Unit as agreed with The Company. The model shall be suitable for the study of balanced, root mean square, positive phase sequence time-domain behaviour, excluding the effects of electromagnetic transients, harmonic and sub-harmonic frequencies.

The model shall accurately represent the overall performance of the Power Park Unit over its entire operating range including that which is inherent to the Power Park Unit and that which is achieved by use of supplementary control systems providing either continuous or stepwise control. Model resolution should be sufficient to accurately represent Power Park Unit behaviour both in response to operation of Transmission System protection and in the context of longer-term simulations.

The overall structure of the model shall include:

(i) any supplementary control signal modules not covered by (c), (d) and (e) below.

(ii) any blocking, deblocking and protective trip features that are part of the Power Park Unit (e.g. “crowbar”).

(iii) any other information required to model the Power Park Unit behaviour to meet the model functional requirement described above.

The model shall be submitted in the form of a transfer function block diagram and may be accompanied by dynamic and algebraic equations.

This model shall display all the transfer functions and their parameter values, any non wind-up logic, signal limits and non-linearities.

The submitted Power Park Unit model and the supplementary control signal module models covered by (c), (d) and (e) below shall have been validated and this shall be confirmed by the Generator. The validation shall be based on comparing the submitted model simulation results against measured test results. Validation evidence shall also be submitted and this shall include the simulation and measured test results. The latter shall include appropriate short-circuit tests. In the case of an Embedded Medium Power Station not subject to a Bilateral Agreement the Network Operator will provide The Company with the validation evidence if requested by The Company. The validation of the supplementary control signal module models covered by (c), (d) and (e) below applies only to a Power Park Module with a Completion Date after 1 January 2009 or Power Park Modules within a Power Generating Module.

(b) Power Park Unit parameters

* Rated MVA

* Rated MW

* Rated terminal voltage

* Average site air density (kg/m³), maximum site air density (kg/m³) and minimum site air density (kg/m³) for the year (as applicable)

Year for which the air density is submitted (as applicable)

Number of pole pairs (as applicable)
Blade swept area (m²) (as applicable)

Gear box ratio (as applicable)

Mechanical drive train (as applicable)

For each **Power Park Unit**, details of the parameters of the drive train (as applicable) represented as an equivalent two mass model should be provided. This model should accurately represent the behaviour of the complete drive train for the purposes of power system analysis studies and should include the following data items:

- Equivalent inertia constant (MWsec/MVA) of the first mass (e.g. wind turbine rotor and blades) at minimum, synchronous and rated speeds
- Equivalent inertia constant (MWsec/MVA) of the second mass (e.g. generator rotor) at minimum, synchronous and rated speeds
- Equivalent shaft stiffness between the two masses (Nm/electrical radian)

Additionally, for **Power Park Units** that are induction generators (e.g. squirrel cage, doubly-fed) driven by wind turbines:

- Stator resistance
- Stator reactance
- Magnetising reactance.
- Rotor resistance (at starting)
- Rotor resistance (at rated running)
- Rotor reactance (at starting)
- Rotor reactance (at rated running)

Additionally for doubly-fed induction generators only:

- The generator rotor speed range (minimum and maximum speeds in RPM)
- The optimum generator rotor speed versus wind speed submitted in tabular format
- Power converter rating (MVA)

The rotor power coefficient ($C_p$) versus tip speed ratio ($\lambda$) curves for a range of blade angles (where applicable) together with the corresponding values submitted in tabular format. The tip speed ratio ($\lambda$) is defined as $\Omega R/U$ where $\Omega$ is the angular velocity of the rotor, $R$ is the radius of the wind turbine rotor and $U$ is the wind speed.

The electrical power output versus generator rotor speed for a range of wind speeds over the entire operating range of the **Power Park Unit**, together with the corresponding values submitted in tabular format.

The blade angle versus wind speed curve together with the corresponding values submitted in tabular format.

The electrical power output versus wind speed over the entire operating range of the **Power Park Unit**, together with the corresponding values submitted in tabular format.

Transfer function block diagram, including parameters and description of the operation of the power electronic converter and fault ride through capability (where applicable).
For a **Power Park Unit** consisting of a synchronous machine in combination with a back to back **DC Converter** or **HVDC System**, 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.

(c) **Torque / speed and blade angle control systems and parameters**

For the type of **Power Park Unit** (as applicable), 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.

(d) **Voltage/Reactive Power/Power Factor** control system parameters

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 showing transfer functions and parameters of individual elements.

(e) **Frequency** control system parameters

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.

(f) **Protection**

Details of settings for the following Protection relays (to include): Under Frequency, over Frequency, under voltage, over voltage, rotor over current, stator over current, high wind speed shut down level.

(g) **Complete Power Park Unit** model, parameters and controls

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.

(h) **Harmonic and flicker parameters**

When connecting a **Power Park Module**, it is necessary for **The Company** to evaluate the production of flicker and harmonics on the National Electricity Transmission System and User's Systems. At The Company's reasonable request, the User (a Network Operator in the case of an Embedded Power Park Module not subject to a Bilateral Agreement) is required to submit the following data (as defined in IEC 61400-21 (2001)) for each Power Park Unit:-

- Flicker coefficient for continuous operation.
- Flicker step factor.
- Number of switching operations in a 10 minute window.
- Number of switching operations in a 2 hour window.
- Voltage change factor.
- Current Injection at each harmonic for each Power Park Unit and for each Power Park Module.

* Data items marked with an asterisk are already requested under part 1, PC.A.3.3.1, to facilitate an early assessment by **The Company** as to whether detailed stability studies will be required before an offer of terms for a **CUSC Contract** can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.
DC Converter and HVDC Systems

For a DC Converter at a DC Converter Station or an HVDC System connected to the Total System by a DC Converter or HVDC System (or in the case of OTSUA which includes an OTSDUW DC Converter) the following information for each DC Converter, HVDC System and DC Network should be supplied:

(a) **DC Converter** and **HVDC System** parameters

   - Rated MW per pole for transfer in each direction;
   - **DC Converter** type (i.e. current or voltage source (including a HVDC Converter in an HVDC System));
   - Number of poles and pole arrangement;
   - Rated DC voltage/pole (kV);
   - Return path arrangement;

(b) **DC Converter** and **HVDC System** transformer parameters

   - Rated MVA
   - Nominal primary voltage (kV);
   - Nominal secondary (converter-side) voltage(s) (kV);
   - Winding and earthing arrangement;
   - Positive phase sequence reactance at minimum, maximum and nominal tap;
   - Positive phase sequence resistance at minimum, maximum and nominal tap;
   - Zero phase sequence reactance;
   - Tap-changer range in %; number of tap-changer steps;

(c) **DC Network** parameters

   - Rated DC voltage per pole;
   - Rated DC current per pole;
   - Single line diagram of the complete **DC Network** and **HVDC System**;
   - Details of the complete **DC Network**, including resistance, inductance and capacitance of all DC cables and/or DC lines and **HVDC System**;
   - Details of any DC reactors (including DC reactor resistance), DC capacitors and/or DC-side filters that form part of the **DC Network** and/or **HVDC System**;

(d) **AC filter reactive compensation equipment parameters**

   - Note: The data provided pursuant to this paragraph must not include any contribution from reactive compensation plant.
   - Total number of AC filter banks.
   - Type of equipment (e.g. fixed or variable)
   - Single line diagram of filter arrangement and connections;
   - **Reactive Power** rating for each AC filter bank, capacitor bank or operating range of each item of reactive compensation equipment, at rated voltage;
   - Performance chart showing **Reactive Power** capability of the **DC Converter** and **HVDC System**, as a function of MW transfer, with all filters and reactive compensation plant, belonging to the **DC Converter Station** or **HVDC System** working correctly.
Note: Details in PC.A.5.4.3.1 are required for each DC Converter connected to the DC Network and HVDC System, unless each is identical or where the data has already been submitted for an identical DC Converter or HVDC System at another Connection Point.

Note: For a Power Park Module and DC Connected Power Park Module connected to the Grid Entry Point or (User System Entry Point if Embedded) by a DC Converter or HVDC System the equivalent inertia and fault infeed at the Power Park Unit should be given.

DC Converter and HVDC System Control System Models

PC.A.5.4.3.2 The following data is required by The Company to represent DC Converters and associated DC Networks and HVDC Systems (and including OTSUA which includes an OTSDUW DC Converter) in dynamic power system simulations, in which the AC power system is typically represented by a positive sequence equivalent. DC Converters and HVDC Systems are represented by simplified equations and are not modelled to switching device level.

(i) Static \( V_{dc} - I_{dc} \) (DC voltage - DC current) characteristics, for both the rectifier and inverter modes for a current source converter. Static \( V_{dc} - P_{dc} \) (DC voltage - DC power) characteristics, for both the rectifier and inverter modes for a voltage source converter.

Transfer function block diagram including parameters representation of the control systems of each DC Converter and of the DC Converter Station and the HVDC System, for both the rectifier and inverter modes. A suitable model would feature the DC Converter or HVDC Converter firing angle as the output variable.

(ii) Transfer function block diagram representation including parameters of the DC Converter or HVDC Converter transformer tap changer control systems, including time delays.

(iii) Transfer function block diagram representation including parameters of AC filter and reactive compensation equipment control systems, including any time delays.

(iv) Transfer function block diagram representation including parameters of any Frequency and/or load control systems.

(v) Transfer function block diagram representation including parameters of any small signal modulation 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.

(vi) Transfer block diagram representation of the Reactive Power control at converter ends for a voltage source converter.

In addition and where not provided for above, HVDC System Owners and Generators in respect of OTSDUW DC Converters who are also EU Code Users shall also provide the following dynamic simulation sub-models

(i) HVDC Converter unit models
(ii) AC component models
(iii) DC Grid models
(iv) Voltage and power controller
(v) Special control features if applicable (eg power oscillation damping (POD) function, subsynchronous torsional interaction (SSTI) control;
(vi) Multi terminal control, if applicable
(vii) HVDC System protection models as agreed between The Company and the HVDC System Owner

HVDC System Owners are also required to supply an equivalent model of the control system when adverse control interactions may result with HVDC Converter Stations and other connections in close proximity if requested by The Company. The equivalent model shall contain all necessary data for the realistic simulation of the adverse control interactions.

Plant Flexibility Performance
PC.A.5.4.3.3 The following information on plant flexibility and performance should be supplied (and also in respect of OTSUA which includes an OTSDUW DC Converter):

(i) Nominal and maximum (emergency) loading rate with the DC Converter or HVDC Converter in rectifier mode.

(ii) Nominal and maximum (emergency) loading rate with the DC Converter or HVDC Converter in inverter mode.

(iii) Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.

(iv) Maximum recovery time, to 90% of pre-fault loading, following a transient DC Network fault.

Harmonic Assessment Information

PC.A.5.4.3.4 DC Converter owners and HVDC System Owners shall provide such additional further information as required by The Company in order that compliance with CC.6.1.5 or ECC.6.1.5 can be demonstrated.

* Data items marked with an asterisk are already requested under part 1, PC.A.3.3.1, to facilitate an early assessment by The Company as to whether detailed stability studies will be required before an offer of terms for a CUSC Contract can be made. Such data items have been repeated here merely for completeness and need not, of course, be resubmitted unless their values, known or estimated, have changed.

PC.A.5.5 Response Data For Frequency Changes

The information detailed below is required to describe the actual frequency response capability profile as illustrated in Figure CC.A.3.1 of the Connection Conditions or Figure ECC.A.3.1 of the European Connection Conditions, and need only be provided for each:

(i) Genset at Large Power Stations; and

(ii) Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module), Power Park Module (including a DC Connected Power Park Module) or CCGT Module at a Medium Power Station or DC Converter Station or HVDC System that has agreed to provide Frequency response in accordance with a CUSC Contract.

In the case of (ii) above for the rest of this PC.A.5.5 where reference is made to Gensets, it shall include such Generating Units (including Synchronous Generating Units within a Synchronous Power Generating Module), CCGT Modules, Power Park Modules (including DC Connected Power Park Modules), HVDC Systems and DC Converters as appropriate, but excludes OTSDUW Plant and Apparatus utilising OTSDUW DC Converters.

In this PC.A.5.5, for a CCGT Module with more than one Generating Unit, the phrase Minimum Generation or Minimum Regulating Level applies to the entire CCGT Module operating with all Generating Units (including Synchronous Generating Units within a Synchronous Power Generating Module) Synchronised to the System. Similarly for a Power Park Module (including a DC Connected Power Park Module) with more than one Power Unit, the phrase Minimum Generation or Minimum Regulating Level applies to the entire Power Park Module operating with all Power Park Units Synchronised to the System.

PC.A.5.5.1 MW Loading Points At Which Data Is Required

Response values are required at six MW loading points (MLP1 to MLP6) for each Genset. Primary and Secondary Response values need not be provided for MW loading points which are below Minimum Generation or Minimum Stable Operating Level. MLP1 to MLP6 must be provided to the nearest MW.

Prior to the Genset being first Synchronised, the MW loading points must take the following values:
MLP1  Designed Minimum Operating Level or Minimum Regulating Level
MLP2  Minimum Generation or Minimum Stable Operating Level
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

When data is provided after the Genset is first Synchronised, the MW loading points may take any value between the Designed Minimum Operating Level or Minimum Regulating Level and Registered Capacity or Maximum Capacity but the value of the Designed Minimum Operating Level or Minimum Regulating Level must still be provided if it does not form one of the MW loading points.

PC.A.5.5.2  Primary And Secondary Response To Frequency Fall

Primary and Secondary Response values for a -0.5Hz ramp are required at six MW loading points (MLP1 to MLP6) as detailed above.

PC.A.5.5.3  High Frequency Response To Frequency Rise

High Frequency Response values for a +0.5Hz ramp are required at six MW loading points (MLP1 to MLP6) as detailed above.

PC.A.5.6  Mothballed Power Generating Module, Mothballed Generating Unit, Mothballed Power Park Module (including DC Connected Power Park Modules), Mothballed HVDC Systems or Mothballed DC Converter at a DC Converter Station And Alternative Fuel Information

Data identified under this section PC.A.5.6 must be submitted as required under PC.A.1.2 and at The Company’s reasonable request. In the case of Embedded Medium Power Stations not subject to a Bilateral Agreement, Embedded HVDC Systems not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement, upon request from The Company each Network Operator shall provide the information required in PC.A.5.6.1, PC.A.5.6.2, PC.A.5.6.3 and PC.A.5.6.4 on respect of such Embedded Medium Power Stations and Embedded DC Converters Stations and Embedded HVDC Systems with their System.

PC.A.5.6.1  Mothballed Generating Unit Information

Generators, HVDC System Owners and DC Converter Station owners must supply with respect to each Mothballed Power Generating Module, Mothballed Generating Unit, Mothballed Power Park Module (including a DC Connected Power Park Module), Mothballed HVDC System or Mothballed DC Converter at a DC Converter Station the estimated MW output which could be returned to service within the following time periods from the time that a decision to return was made:

- < 1 month;
- 1-2 months;
- 2-3 months;
- 3-6 months;
- 6-12 months; and
- >12 months.

The return to service time should be determined in accordance with Good Industry Practice assuming normal working arrangements and normal plant procurement lead times. The MW output values should be the incremental values made available in each time period as further described in the DRC.
Generators, HVDC System Owners and DC Converter Station owners must also notify The Company of any significant factors which may prevent the Mothballed Power Generating Module, Mothballed Generating Unit, Mothballed Power Park Module (including DC Connected Power Park Modules), Mothballed HVDC Systems or Mothballed DC Converter at a DC Converter Station achieving the estimated values provided under PC.A.5.6.1 above, excluding factors relating to Transmission Entry Capacity.

PC.A.5.6.3 Alternative Fuel Information

The following data items must be supplied with respect to each Generating Unit (including Synchronous Generating Units within a Synchronous Power Generating Module) whose main fuel is gas.

For each alternative fuel type (if facility installed):

(a) Alternative fuel type e.g. oil distillate, alternative gas supply

(b) For the changeover from main to alternative fuel:
   - Time to carry out off-line and on-line fuel changeover (minutes).
   - Maximum output following off-line and on-line changeover (MW).
   - Maximum output during on-line fuel changeover (MW).
   - Maximum operating time at full load assuming typical and maximum possible stock levels (hours).
   - Maximum rate of replacement of depleted stocks (MWh electrical/day) on the basis of Good Industry Practice.
   - Is changeover to alternative fuel used in normal operating arrangements?
   - Number of successful changeovers carried out in the last of The Company’s Financial Year (choice of 0, 1-5, 6-10, 11-20, >20).

(c) For the changeover back to main fuel:
   - Time to carry out off-line and on-line fuel changeover (minutes).
   - Maximum output during on-line fuel changeover (MW).

PC.A.5.6.4 Generators must also notify The Company of any significant factors and their effects which may prevent the use of alternative fuels achieving the estimated values provided under PC.A.5.6.3 above (e.g. emissions limits, distilled water stocks etc.)

PC.A.5.7 Black Start Related Information

Data identified under this section PC.A.5.7 must be submitted as required under PC.A.1.2. This information may also be requested by The Company during a Black Start and should be provided by Generators, HVDC System Owners and DC Converter Station Owners where reasonably possible. For the avoidance of doubt, Generators in this section PC.A.5.7 means Generators only in respect of their Large Power Stations.

The following data items/text must be supplied, from each Generator, HVDC System Owner and DC Converter Station Owner to The Company. In the case of Generators, the data supplied should be with respect to each BM Unit at a Large Power Station. For the avoidance of doubt, the data required under PC.A.5.7 (a) and (b) below, does i) not need to be supplied in respect of Generators that are contracted to provide a Black Start Capability and ii), the data only needs to be supplied in respect of the BM Unit at a Large Power Station and does not need to include Generating Unit data;

(a) Expected time for each BM Unit to be Synchronised following a Total Shutdown or Partial Shutdown. The assessment should include the Power Station’s or HVDC System’s or DC Converter Station’s ability to re-synchronise all BM Units, if all were running immediately prior to the Total Shutdown or Partial Shutdown. Additionally this should highlight any specific issues (i.e. those that would impact on the BM Unit’s time to be Synchronised) that may arise, as time progresses without external supplies being restored.
(b) **Block Loading Capability.** This should be provided in either graphical or tabular format showing the estimated block loading capability from 0MW to Registered Capacity. Any particular 'hold' points should also be identified. The data of each BM Unit should be provided for the condition of a Generating Unit (which is considered as both a 'hot' unit and cold unit) that was Synchronised just prior to the Total Shutdown or Partial Shutdown. In the case of an HVDC System or DC Converter Station, data should be provided when the HVDC System or DC Converter Station has been considered to have run immediately before the Total Shutdown or Partial Shutdown and equally when the HVDC System or DC Converter Station has been considered to have been Shutdown for a period of 48 hours or more. The block loading assessment should be done against a frequency variation of 49.5Hz – 50.5Hz.

PC.A.5.8 Grid Forming Related Information

PC.A.5.8.1 The following data need only be supplied by Users (be they a GB Code User or EU Code User) or Non-CUSC Parties who wish to offer a Grid Forming Capability as provided for ECC.6.3.19.3. Where such a Grid Forming Capability is provided then the following data items and models are to be supplied.

(i) Each GBGF-I shall be designed so as not to interact and affect the operation, performance, safety or capability of other User’s Plant and Apparatus connected to the Total System. To achieve this requirement, each User shall be required to submit a Network Frequency Perturbation Plot and Nichols Chart (or equivalent as agreed with The Company) which shall be assessed in accordance with the requirements of ECP.A.3.9.3.

Each User or Non-CUSC Party is required to supply a high level equivalent architecture diagram of their Grid Forming Plant as shown in Figure PC.A.5.8.1 together with the equivalent linear classical block diagram model (using the Laplace Operator) of their Grid Forming Plant which should preferably be in the general form shown in Figure PC.A.5.8.1 (a) or Figure PC.A.5.8.1 (b). When submitting either Figure PC.A.5.8.1 (a) or Figure PC.A.5.8.1 (b), each User or Non-CUSC Party can use their own design, that may be very different to Figures PC.A.5.8.1 (a) or PC.A.5.8.1 (b), but should contain all relevant functions that can include simulation models and other equivalent data and documentation.

Each User or Non-CUSC Party shall provide a model of their Grid Forming Plant which provides a true and accurate reflection of its Grid Forming Capability.

![Figure PC.A.5.8.1](image-url)
Figure PC.A.5.8.1 (a) Preferred simplified diagram of a GBGF-I with a Power System Stabiliser “PSS” that can add damping to the GBGF-I’s closed loop function shown by the solid red line and the dotted blue line.

Figure PC.A.5.8.1 (b) – Preferred simplified diagram of a system with a droop control ability that can add Control-Based Active Droop Power. This diagram does not add extra closed loop damping to the GBGF-I’s closed loop function shown by the solid red line and the dotted blue line.

(ii) In order to participate in the Grid Forming Capability market, User’s and Non-CUSC Parties are required to provide data of their GBGF-I in accordance with Figures PC.A.5.8.1(a) and PC.A.5.8.1(b). Users and Non-CUSC Parties in respect of Grid Forming Plants should indicate if the data is submitted on a unit or aggregated basis. Table PC.A.5.8.1(a) defines the notation used in Figure PC.5.8.1

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>The primary reactance of the Grid Forming Unit, in pu.</td>
<td>Xin or Xts</td>
<td>pu on MVA Rating of Grid Forming Unit</td>
</tr>
<tr>
<td>The additional reactance, in pu, between the terminals of the Grid Forming Unit and the Grid Entry Point or User System Entry Point (if Embedded).</td>
<td>Xtr</td>
<td>pu on MVA Rating of Grid Forming Unit</td>
</tr>
<tr>
<td>The rated angle between the Internal Voltage Source and the input terminals of the Grid Forming Unit.</td>
<td></td>
<td>radians</td>
</tr>
<tr>
<td>The rated angle between the Internal Voltage Source and Grid Entry Point or User System Entry Point (if Embedded).</td>
<td></td>
<td>radians</td>
</tr>
</tbody>
</table>
The rated voltage and phase of the Internal Voltage Source of the Grid Forming Unit.

<table>
<thead>
<tr>
<th>Voltage - pu</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase - radians</td>
</tr>
</tbody>
</table>

The rated electrical angle between current and voltage at the input to the Grid transformer.

| radians |

Table PC.A.5.8.1

(iii) In order to participate in a Grid Forming Capability market, User’s and Non-CUSC Parties are also required to provide the data of their GBGF-I in accordance with Table PC.A.5.8.1.2 to The Company. The details and arrangements for Users and Non-CUSC Parties participating in this market shall be published on The Company’s Website.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Units</th>
<th>Range (where Applicable)</th>
<th>User Defined Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Grid Forming Plant (eg Generating Unit, Electricity Storage Module, Dynamic Reactive Compensation Equipment etc)</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Continuous Rating at Registered Capacity or Maximum Capacity</td>
<td>MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary reactance Xin or Xts (see Table PC.A.5.8.1)</td>
<td>pu on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Additional reactance Xₚ (See Table PC.A.5.8.1)</td>
<td>pu on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Capacity</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Active ROCOF Response Power (MW) injected or absorbed at 1Hz/s System Frequency change (which is the maximum frequency change for linear operation of the Grid Forming Plant)</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase Jump Angle Withstand</td>
<td>degrees</td>
<td>60 degrees specified</td>
<td></td>
</tr>
<tr>
<td>Phase Jump Angle limit</td>
<td>degrees</td>
<td>5 degrees recommended</td>
<td></td>
</tr>
<tr>
<td>Phase Jump Power (MW) at the rated angle</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Defined Active Damping Power for a Grid Oscillation Value of 0.05 Hz peak to peak at 1 Hz</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>The cumulative energy delivered for a 1Hz/s <strong>System Frequency</strong> fall from 52 Hz to 47 Hz. This is the total <strong>Active Power</strong> transient output of the <strong>Grid Forming Plant</strong></td>
<td>MWs or MJ</td>
<td></td>
<td></td>
</tr>
<tr>
<td>---</td>
<td>---</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Inertia Constant (H)</strong> using equation 1 or declared in accordance with the simulation results of ECP.A.3.9.4</td>
<td>MWs/MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Inertia Constant (He)</strong> using equation 2 or declared in accordance with the simulation results of ECP.A.3.9.4</td>
<td>MWs/MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Continuous Overload Capability</td>
<td>% on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Short Term duration Overload capability</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Duration of Short Term Overload Capability</td>
<td>s</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Peak Current Rating</strong></td>
<td>Pu</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal <strong>Grid Entry Point or User System Entry Point</strong> voltage</td>
<td>kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grid Entry Point or User System Entry Point</strong></td>
<td>- Location</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Continuous or defined time duration MVA Rating</td>
<td>MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Continuous or defined time duration MW Rating</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>For a <strong>GBGF-I</strong> the inverters maximum <strong>Internal Voltage Source (IVS)</strong> for the worst case condition – for example operation at maximum exporting <strong>Reactive Power</strong> at the maximum <strong>AC System voltage</strong></td>
<td>pu</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Three Phase Short Circuit Infeed at Grid Entry Point or User System Entry Point</strong></td>
<td>kA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Single Phase Short Circuit Infeed at Grid Entry Point or User System Entry Point</strong></td>
<td>kA</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Will the **Grid Forming Plant** contribute to any other form of commercial service – for example, Dynamic Containment, Firm Frequency Response, Details to be provided

| Equivalent Damping Factor | Z | 0.2 to 5.0 allowed |

Table PC.A.5.8.2

\[
H = \frac{\text{Installed MWs / Rated installed MVA}}{}
\]

\[
He = \frac{(\text{Active ROCOF Response Power} \text{ at } 1 \text{ Hz / s x System Frequency})}{(\text{Installed MVA} \times 2)}
\]

PC.A.6 **USERS’ SYSTEM DATA**

PC.A.6.1 **Introduction**

PC.A.6.1.1 Each **User**, whether connected directly via an existing **Connection Point** to the **National Electricity Transmission System** or seeking such a direct connection, or providing items for connection of an **Offshore Transmission System** to its **User System** to **The Company** or undertaking **OTSDUW**, shall provide **The Company** with data on its **User System** or **OTSDUW Plant and Apparatus** which relates to the **Connection Site** containing the **Connection Point** (or **Interface Points** or **Connection Points** in the case of **OTSUA**) both current and forecast, as specified in PC.A.6.2 to PC.A.6.6.

PC.A.6.1.2 Each **User** must reflect the system effect at the **Connection Site(s)** of any third party **Embedded** within its **User System** whether existing or proposed.

PC.A.6.1.3 PC.A.6.2, and PC.A.6.4 to PC.A.6.7 consist of data which is only to be supplied to **The Company** at **The Company’s** reasonable request. In the event that **The Company** identifies a reason for requiring this data, **The Company** shall write to the relevant **User(s)**, requesting the data, and explaining the reasons for the request. If the **User(s)** wishes, **The Company** shall also arrange a meeting at which the request for data can be discussed, with the objective of identifying the best way in which **The Company’s** requirements can be met. In respect of **EU Code User(s)** only, **The Company** may request the need for electromagnetic transient simulations at **The Company’s** reasonable request. **Users** with **EU Grid Supply Points** may be required to provide electromagnetic transient simulations in relation to those **EU Grid Supply Points at **The Company’s** reasonable request.

Where **The Company** makes a request to a **User** for dynamic models under PC.A.6.7, each relevant **User** shall ensure that the models supplied in respect of their **Plant** and **Apparatus** reflect the true and accurate behaviour of the **Plant** and **Apparatus** as built and verified through the **Compliance Processes (CP’s)** or **European Compliance Processes (ECP)**.

PC.A.6.2 **Transient Overvoltage Assessment Data**

PC.A.6.2.1 It is occasionally necessary for **The Company** to undertake transient overvoltage assessments (e.g. capacitor switching transients, switchgear transient recovery voltages, etc). At **The Company’s** reasonable request, each **User** is required to provide the following data with respect to the **Connection Site** (and in the case of **OTSUA, Interface Points** and **Connection Points**), current and forecast, together with a **Single Line Diagram** where not already supplied under PC.A.2.2.1, as follows:
(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 (including OTSUA at each Interface Point and Connection Point) 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 or greater (including OTSUA): 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.

PC.A.6.3 User's Protection Data

PC.A.6.3.1 Protection

The following information is required which relates only to Protection equipment which can trip or inter-trip or close any Connection Point circuit-breaker or any Transmission circuit-breaker (or in the case of OTSUA, any Interface Point or Connection Point circuit breaker). This 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;

(b) a full description of any auto-reclose facilities installed or to be installed on the User’s System, including type and time delays;

(c) a full description, including estimated settings, for all relays and Protection systems or to be installed on the generator, generator transformer, Station Transformer and their associated connections;

(d) for Generating Units (including Synchronous Generating Units forming part of a Synchronous Power Generating Module but excluding Power Park Units) or Power Park Modules (including DC Connected Power Park Modules) or HVDC Systems or DC Converters at a DC Converter Station or OTSDUW Plant and Apparatus having (or intended to have) a circuit breaker at the generator terminal voltage, clearance times for electrical faults within the Generating Unit (including Synchronous Generating Units forming part of a Synchronous Power Generating Module but excluding a Power Park Unit) or Power Park Module (including DC Connected Power Park Modules) zone, or within the OTSDUW Plant and Apparatus;

(e) the most probable fault clearance time for electrical faults on any part of the User’s System directly connected to the National Electricity Transmission System including OTSDUW Plant and Apparatus; and

(f) in the case of OTSDUW Plant and Apparatus, synchronisation facilities and delayed auto reclose sequence schedules (where applicable).
PC.A.6.4 Harmonic Studies

PC.A.6.4.1 It is occasionally necessary for The Company to evaluate the production/magnification of harmonic distortion on the National Electricity Transmission System and User’s Systems (and OTSUA), especially when The Company is connecting equipment such as capacitor banks. At The Company’s reasonable request, each User is required to submit data with respect to the Connection Site (and in the case of OTSUA, each Interface Point and Connection Point), current and forecast, and where not already supplied under PC.A.2.2.4 and PC.A.2.2.5, as follows:

PC.A.6.4.2 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;

and for all transformers connecting the User’s Subtransmission System and OTSDUW Plant and Apparatus to a lower voltage:

- Rated MVA;
- Voltage Ratio;
- Positive phase sequence resistance;
- Positive phase sequence reactance;

and 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. Where the harmonic injection current comes from a diverse group of sources, the equivalent contribution may be established from appropriate measurements;
- Details of traction loads, eg connection phase pairs, continuous variation with time, etc;
- An indication of which items of equipment may be out of service simultaneously during Planned Outage conditions.

PC.A.6.5 Voltage Assessment Studies

It is occasionally necessary for The Company to undertake detailed voltage assessment studies (e.g., to examine potential voltage instability, voltage control co-ordination or to calculate voltage step changes). At The Company’s reasonable request, each User is required to submit the following data where not already supplied under PC.A.2.2.4 and PC.A.2.2.5:

For all circuits of the User’s Subtransmission System (and any OTSUA):

- Positive Phase Sequence Reactance;
- Positive Phase Sequence Resistance;
- Positive Phase Sequence Susceptance;
- MVAr rating of any reactive compensation equipment;

and for all transformers connecting the User’s Subtransmission System to a lower voltage (and any OTSUA):

- 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;

and at the lower voltage points of those connecting transformers (and any OTSUA):
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.

PC.A.6.6 Short Circuit Analysis

PC.A.6.6.1 Where prospective short-circuit currents on Transmission equipment are greater than 90% of the equipment rating, and in The Company’s reasonable opinion more accurate calculations of short-circuit currents are required, then at The Company’s request each User is required to submit data with respect to the Connection Site (and in the case of OTSUA, each Interface Point and Connection Point), current and forecast, and where not already supplied under PC.A.2.2.4 and PC.A.2.2.5, as follows:

PC.A.6.6.2 For all circuits of the User’s Subtransmission System (and any OTSUA):
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);

and for all transformers connecting the User’s Subtransmission System to a lower voltage (and any OTSUA):
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;

and at the lower voltage points of those connecting transformers (and any OTSUA):
The maximum Demand (in MW and MVAr) that could occur;
Short-circuit infeed data in accordance with PC.A.2.5.6 unless the User’s lower voltage network runs in parallel with the User’s Subtransmission System, when to prevent double counting in each node infeed data, a \( \pi \) equivalent comprising the data items of PC.A.2.5.6 for each node together with the positive phase sequence interconnection impedance between the nodes shall be submitted.

**PC.A.6.7 Dynamic Models**

**PC.A.6.7.1** It is occasionally necessary for The Company to evaluate the dynamic performance of User’s Plant and Apparatus at each EU Grid Supply Point or in the case of EU Code Users, their System. At The Company’s reasonable request and as agreed between The Company and the relevant Network Operator or Non-Embedded Customer, each User is required to provide the following data. Where such data is required, The Company will work with the Network Operator or Non-Embedded Customer to establish the scope of the dynamic modelling work and share the required information where it is available:

(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).

**PC.A.7 ADDITIONAL DATA FOR NEW TYPES OF POWER STATIONS, DC CONVERTER STATIONS, OTSUA AND CONFIGURATIONS**

Notwithstanding the Standard Planning Data and Detailed Planning Data set out in this Appendix, as new types of configurations and operating arrangements of Power Stations, HVDC Systems, DC Converter Stations and OTSUA emerge in future, The Company may reasonably require additional data to represent correctly the performance of such Plant and Apparatus on the System, where the present data submissions would prove insufficient for the purpose of producing meaningful System studies for the relevant parties.
PART 3 - DETAILED PLANNING DATA

PC.A.8 To allow a User to model the National Electricity Transmission System, The Company will provide, upon request, the following Network Data to Users, calculated in accordance with Good Industry Practice:

To allow a User to assess undertaking OTSDUW and except where provided for in Appendix F, The Company will provide upon request the following Network Data to Users, calculated in accordance with Good Industry Practice:

PC.A.8.1 Single Point of Connection

For a Single Point of Connection to a User’s System (and OTSUA), as a Transmission System voltage source, the data (as at the HV side of the Point of Connection (and in the case of OTSUA, each Interface Point and Connection Point) reflecting data given to The Company by Users) will be given to a User as follows:

The data items listed under the following parts of PC.A.8.3:
(a) (i), (ii), (iii), (iv), (v) and (vi) and the data items shall be provided in accordance with the detailed provisions of PC.A.8.3 (b) - (e).

PC.A.8.2 Multiple Point of Connection

For a Multiple Point of Connection to a User’s System equivalents suitable for use in loadflow and fault level analysis shall be provided. These equivalents will normally be in the form of a π model or extension with a source (or demand for a loadflow equivalent) at each node and a linking impedance. The boundary nodes for the equivalent shall be either at the Connection Point (and in the case of OTSDUW, each Interface Point and Connection Point) or (where The Company agrees) at suitable nodes (the nodes to be agreed with the User) within the National Electricity Transmission System. The data at the Connection Point (and in the case of OTSDUW, each Interface Point and Connection Point) will be given to a User as follows:

The data items listed under the following parts of PC.A.8.3:-
(a) (i), (ii), (iv), (v), (vi), (vii), (ix), (x) and (xi)

and the data items shall be provided in accordance with the detailed provisions of PC.A.8.3 (b) - (e).

When an equivalent of this form is not required The Company will not provide the data items listed under the following parts of PC.A.8.3:-
(a) (vii), (viii), (ix), (x) and (xi)

PC.A.8.3 Data Items

(a) The following is a list of data utilised in this part of the PC. It also contains rules on the data which generally apply.

(i) symmetrical three-phase short circuit current infeed at the instant of fault from the National Electricity Transmission System, \(I_{1}^{*}\);

(ii) symmetrical three-phase short circuit current from the National Electricity Transmission System after the subtransient fault current contribution has substantially decayed, \(I_{1}^{*}\);

(iii) the zero sequence source resistance and reactance values at the Point of Connection (and in case of OTSUA, each Interface Point and Connection Point), consistent with the maximum infeed below;

(iv) the pre-fault voltage magnitude at which the maximum fault currents were calculated;

(v) the positive sequence X/R ratio at the instant of fault;

(vi) the negative sequence resistance and reactance values of the National Electricity Transmission System seen from the Point of Connection (and in case of OTSUA, each Interface Point and Connection Point), if substantially different from the
values of positive sequence resistance and reactance which would be derived from the data provided above;

(vii) the initial positive sequence resistance and reactance values of the two (or more) sources and the linking impedance(s) derived from a fault study constituting the (π) equivalent and evaluated without the User network and load and where appropriate without elements of the National Electricity Transmission System between the User network and agreed boundary nodes (and in case of OTSUA, each Interface Point and Connection Point);

(viii) the positive sequence resistance and reactance values of the two (or more) sources and the linking impedance(s) derived from a fault study, considering the short circuit current contributions after the subtransient fault current contribution has substantially decayed, constituting the (π) equivalent and evaluated without the User network and load, and where appropriate without elements of the National Electricity Transmission System between the User network and agreed boundary nodes (and in case of OTSUA, each Interface Point and Connection Point);

(ix) the corresponding zero sequence impedance values of the (π) equivalent produced for use in fault level analysis;

(x) the Demand and voltage at the boundary nodes and the positive sequence resistance and reactance values of the linking impedance(s) derived from a loadflow study considering National Electricity Transmission System peak Demand constituting the (π) loadflow equivalent; and,

(xii) where the agreed boundary nodes are not at a Connection Point (and in case of OTSUA, Interface Point or Connection Point), the positive sequence and zero sequence impedances of all elements of the National Electricity Transmission System between the User network and agreed boundary nodes that are not included in the equivalent (and in case of OTSUA, each Interface Point and Connection Point).

(b) To enable the model to be constructed, The Company will provide data based on the following conditions.

(c) The initial symmetrical three phase short circuit current and the transient period three phase short circuit current will normally be derived from the fixed impedance studies. The latter value should be taken as applying at times of 120ms and longer. Shorter values may be interpolated using a value for the subtransient time constant of 40ms. These fault currents will be obtained from a full System study based on load flow analysis that takes into account any existing flow across the point of connection being considered.

(d) The Company will provide the appropriate supergrid transformer data for the National Electricity Transmission System associated with equivalent voltage source data.

(e) The positive sequence X/R ratio and the zero sequence impedance value will correspond to The Company's source network only, that is with the section of network if any with which the equivalent is to be used excluded. These impedance values will be derived from the condition when all Generating Units (including Synchronous Generating Units forming part of a Synchronous Power Generating Module) are Synchronised to the National Electricity Transmission System or a User's System and will take account of active sources only including any contribution from the load to the fault current. The passive component of the load itself or other system shunt impedances should not be included.

(f) A User may at any time, in writing, specifically request for an equivalent to be prepared for an alternative System condition, for example where the User's System peak does not correspond to the National Electricity Transmission System peak, and The Company will, insofar as such request is reasonable, provide the information as soon as reasonably practicable following the request.
APPENDIX B - SINGLE LINE DIAGRAMS

PC.B.1 The diagrams below show three examples of single line diagrams, showing the detail that should be incorporated in the diagram. The first example is for an Network Operator connection, the second for a Generator connection, the third for a Power Park Module electrically equivalent system.

Network Operator Single Line Diagram
Notes:

(1) The electrically equivalent Power Park Unit consists of a number of actual Power Park Units of the same type i.e., any equipment external to the Power Park Unit terminals is considered as part of the equivalent network. Power Park Units of different types shall be included in separate electrically equivalent Power Park Units. The total number of equivalent Power Park Units shall represent all of the actual Power Park Units in the Power Park Module (which could be a DC Connected Power Park Module).

(2) Separate electrically equivalent networks are required for each different type of electrically equivalent Power Park Unit. The electrically equivalent network shall include all equipment between the Power Park Unit terminals and the Common Collection Busbar.

(3) All Plant and Apparatus including the circuit breakers, transformers, lines, cables, and reactive compensation plant between the Common Collection Busbar and Substation A shall be shown.
Planning and design of the SPT and SHETL Transmission Systems is based generally, but not totally, on criteria which evolved from joint consultation among various Transmission Licensees responsible for design of the National Electricity Transmission System.

The above criteria are set down within the standards, memoranda, recommendations and reports and are provided as a guide to system planning. It should be noted that each scheme for reinforcement or modification of the Transmission System is individually designed in the light of economic and technical factors associated with the particular system limitations under consideration.

The tables below identify the literature referred to above, together with the main topics considered within each document.

### PART 1 – SHETL’s TECHNICAL AND DESIGN CRITERIA

<table>
<thead>
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<th>ITEM No.</th>
<th>DOCUMENT</th>
<th>REFERENCE No.</th>
</tr>
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<tbody>
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<td>1</td>
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<td>Version [ ]</td>
</tr>
<tr>
<td>2</td>
<td>System Phasing</td>
<td>TPS 13/4</td>
</tr>
<tr>
<td>3</td>
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<tr>
<td>4</td>
<td>Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom</td>
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<td>8</td>
<td>Operational Memoranda</td>
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<td></td>
<td>Main System operating procedure.</td>
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<td>SOM 3</td>
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<td>Emergency action in the event of an exceptionally serious breakdown of the main system.</td>
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<td>Planning Limits for Voltage Unbalance in the United Kingdom.</td>
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### PART 2 - SPT’s TECHNICAL AND DESIGN CRITERIA

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<td>7</td>
<td>AC Traction Supplies to British Rail</td>
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</table>

- **Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom:**
  - Voltage Unbalance limits.
  - Harmonic current limits.

- **EHV or HV Supplies to Induction Furnaces:**
  - Voltage Unbalance limits.
  - Harmonic current limits.

- **Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Loads to Transmission Systems and Public Electricity Supply Systems in the United Kingdom:**
  - Harmonic distortion (waveform).
  - Harmonic voltage distortion.
  - Harmonic current distortion.
  - Stage 1 limits.
  - Stage 2 limits.
  - Stage 3 Limits
  - Addition of Harmonics
  - Short Duration Harmonics
  - Site Measurements

- **AC Traction Supplies to British Rail:**
  - Type of supply point to railway system.
  - Estimation of traction loads.
  - Nature of traction current.
  - System disturbance estimation.
  - Earthing arrangements.
Pursuant to PC.3.4, The Company will not disclose to a Relevant Transmission Licensee data items specified in the below extract:

<table>
<thead>
<tr>
<th>PC REFERENCE</th>
<th>DATA DESCRIPTION</th>
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<td></td>
<td>The Generator Performance Chart at the Generating Unit stator terminals</td>
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<td>(ii) For EU Code Users:</td>
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<td></td>
<td>The Power Generating Module Performance Chart, and Synchronous Generating Unit Performance Chart;</td>
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<td>Output Usable (on a monthly basis)</td>
<td>MW</td>
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<td>GOVERNOR AND ASSOCIATED PRIME MOVER PARAMETERS</td>
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<td>Option 1</td>
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<td>BOILER &amp; STEAM TURBINE DATA</td>
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<td>Boiler time constant (Stored Active Energy)</td>
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<td>DPD II</td>
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<td>HP turbine response ratio: (Proportion of Primary Response arising from HP turbine)</td>
<td>%</td>
<td>DPD II</td>
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<td></td>
<td>HP turbine response ratio: (Proportion of High Frequency Response arising from HP turbine)</td>
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<td>- Maximum Setting</td>
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<td>- Minimum Setting</td>
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<td>*(Note GB Generators who are not required to satisfy the requirements of the European Connection Conditions do not need to supply Frequency Response Deadband or Frequency Response Insensitivity data).</td>
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<td>Reheater Time Constant</td>
<td>sec</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Boiler Time Constant</td>
<td>sec</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>HP Power Fraction</td>
<td>%</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>IP Power Fraction</td>
<td>%</td>
<td>DPD II</td>
</tr>
<tr>
<td>Part of PC.A.5.3.2 (d) Option 2 (iii)</td>
<td>Gas Turbine Units</td>
<td>Waste Heat Recovery Boiler Time Constant</td>
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<td>Part of PC.A.5.3.2 (e)</td>
<td>UNIT CONTROL OPTIONS</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Maximum droop</td>
<td>%</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Minimum droop</td>
<td>%</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Maximum Governor Deadband or (Maximum Frequency Response Deadband and Maximum Frequency Response Insensitivity)*</td>
<td>±Hz</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Normal Governor Deadband or (normal Frequency Response Deadband and normal Frequency Response Insensitivity)*</td>
<td>±Hz</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Minimum Governor Deadband or (minimum Frequency Response Deadband and minimum Frequency Response Insensitivity)*</td>
<td>±Hz</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Maximum Output Governor Deadband or (Maximum Output Frequency Response Deadband and Maximum Output Frequency Response Insensitivity)*</td>
<td>±MW</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Normal Output Governor Deadband or (Normal Output Frequency Response Deadband and Normal Output Frequency Response Insensitivity)*</td>
<td>±MW</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Minimum Output Governor Deadband or (Minimum Output Frequency Response Deadband and Minimum Output Frequency Response Insensitivity)*</td>
<td>±MW</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Frequency settings between which Unit Load Controller droop applies:</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Maximum</td>
<td>Hz</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Normal</td>
<td>Hz</td>
<td>DPD II</td>
</tr>
<tr>
<td></td>
<td>Minimum</td>
<td>Hz</td>
<td>DPD II</td>
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<td>Sustained response normally selected</td>
<td>Yes/No</td>
<td>DPD II</td>
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<td>PC.A.3.2.2 (f) (ii)</td>
<td>Performance Chart of a Power Park Modules (including DC Connected Power Park Modules) at the connection point</td>
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<td>SPD</td>
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<td>PC REFERENCE</td>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA CATEGORY</td>
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<td>ACTIVE POWER TRANSFER CAPABILITY (PC.A.3.2.2)</td>
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<td>Import MW available in excess of Registered Import Capacity.</td>
<td>MW</td>
<td>SPD</td>
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<td></td>
<td>Time duration for which MW in excess of Registered Import Capacity is available</td>
<td>Min</td>
<td>SPD</td>
</tr>
<tr>
<td></td>
<td>Export MW available in excess of Registered Capacity.</td>
<td>MW</td>
<td>SPD</td>
</tr>
<tr>
<td></td>
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<td>Min</td>
<td>SPD</td>
</tr>
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<td></td>
<td>MW Export</td>
<td>MW</td>
<td>SPD</td>
</tr>
<tr>
<td></td>
<td>Nominal loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
</tr>
<tr>
<td></td>
<td>Maximum (emergency) loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
</tr>
<tr>
<td></td>
<td>MW Import</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Nominal loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
</tr>
<tr>
<td></td>
<td>Maximum (emergency) loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
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APPENDIX E - OFFSHORE TRANSMISSION SYSTEM AND OTSDUW PLANT AND APPARATUS
TECHNICAL AND DESIGN CRITERIA

PC.E.1  In the absence of any relevant Electrical Standards, Offshore Transmission Licensees and Generators undertaking OTSDUW are required to ensure that all equipment used in the construction of their network is:

(i) Fully compliant and suitably designed to any relevant Technical Specification;

(ii) Suitable for use and operation in an Offshore environment, where such parts of the Offshore Transmission System and OTSDUW Plant and Apparatus are located in Offshore Waters and are not installed in an area that is protected from that Offshore environment, and

(iii) Compatible with any relevant Electrical Standards or Technical Specifications at the Offshore Grid Entry Point and Interface Point.

PC.E.2  The table below identifies the technical and design criteria that will be used in the design and development of an Offshore Transmission System and OTSDUW Plant and Apparatus.

<table>
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<th>DOCUMENT</th>
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<tr>
<td>1</td>
<td>National Electricity Transmission System Security and Quality of Supply Standard</td>
<td>Version [ ]</td>
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<td>2*</td>
<td>Voltage fluctuations and the connection of disturbing equipment to transmission systems and distribution networks in the United Kingdom</td>
<td>EREC P28 Issue 2</td>
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<td>3*</td>
<td>Planning Levels for Harmonic Voltage Distortion and the Connection of Non-Linear Loads to Transmission Systems and Public Electricity Supply Systems in the United Kingdom</td>
<td>ER G5</td>
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<td>ER P29</td>
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* Note: Items 2, 3 and 4 above shall only apply at the Interface Point.
APPENDIX F - OTSDUW DATA AND INFORMATION AND OTSDUW NETWORK DATA AND INFORMATION

PC.F.1 Introduction
PC.F.1.1 Appendix F specifies data requirements to be submitted to The Company by Users and Users by The Company in respect of OTSDUW.
PC.F.1.2 Such User submissions shall be in accordance with the OTSDUW Development and Data Timetable in a Construction Agreement.
PC.F.1.3 Such submissions shall be issued to The Company with the offer of a CUSC Contract in the case of the data in Part 1 and otherwise in accordance with the OTSDUW Development and Data Timetable in a Construction Agreement.

PC.F.2 OTSDUW Network Data and Information
PC.F.2.1 With the offer of a CUSC Contract under the OTSDUW Arrangements The Company shall provide:

(a) the site specific technical design and operational criteria for the Connection Site;
(b) the site specific technical design and operational criteria for the Interface Point, and
(c) details of The Company’s preliminary identification and consideration of the options available for the Interface Point in the context of the User’s application for connection or modification, the preliminary costs used by The Company in assessing such options and the Offshore Works Assumptions including the assumed Interface Point identified during these preliminary considerations.

PC.F.2.2 In accordance with the OTSDUW Development and Data Timetable in a Construction Agreement The Company shall provide the following information and data to a User:

(a) equivalent of the fault infeed or fault level ratings at the Interface Point (as identified in the Offshore Works Assumptions)
(b) notification of numbering and nomenclature of the HV Apparatus comprised in the OTSDUW;
   (i) past or present physical properties, including both actual and designed physical properties, of Plant and Apparatus forming part of the National Electricity Transmission System at the Interface Point at which the OTSUA will be connected to the extent it is required for the design and construction of the OTSDUW, including but not limited to:
   (ii) the voltage of any part of such Plant and Apparatus;
   (iii) the electrical current flowing in or over such Plant and Apparatus;
   (iv) the configuration of any part of such Plant and Apparatus
   (v) the temperature of any part of such Plant and Apparatus;
   (vi) the pressure of any fluid forming part of such Plant and Apparatus
   (vii) the electromagnetic properties of such Plant and Apparatus; and
   (viii) the technical specifications, settings or operation of any Protection Systems forming part of such Plant and Apparatus.
(c) information necessary to enable the User to harmonise the OTSDUW with construction works elsewhere on the National Electricity Transmission System that could affect the OTSDUW;
(d) information related to the current or future configuration of any circuits of the Onshore Transmission System with which the OTSUA are to connect;
(e) any changes which are planned on the National Electricity Transmission System in the current or following six Financial Years and which will materially affect the planning or development of the OTSDUW.
PC.F.2.3 At the Users reasonable request, additional information and data in respect of the National Electricity Transmission System shall be provided.

PC.F.2.4 OTSDUW Data And Information

PC.F.2.4.1 In accordance with the OTSDUW Development and Data Timetable in a Construction Agreement, the User shall provide to The Company, the following information and data relating to the OTSDUW Plant and Apparatus in accordance with Appendix A of the Planning Code.

< END OF PLANNING CODE >
## CONNECTION CONDITIONS (CC)

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INTRODUCTION

The Connection Conditions ("CC") specify both:

(a) the minimum technical, design and operational criteria which must be complied with by:

   (i) any GB Code User connected to or seeking connection with the National Electricity Transmission System, or

   (ii) GB Code User's in respect of GB Generators (other than in respect of Small Power Stations) or GB Code User's in respect of DC Converter Station owners connected to or seeking connection to a User's System which is located in Great Britain or Offshore, and

(b) the minimum technical, design and operational criteria with which The Company will comply in relation to the part of the National Electricity Transmission System at the Connection Site with GB Code Users. In the case of any OTSDUW Plant and Apparatus, the CC also specify the minimum technical, design and operational criteria which must be complied with by those GB Code Users when undertaking OTSDUW.

(c) For the avoidance of doubt, the requirements of these CC’s do not apply to EU Code User’s for whom the requirements of the ECC’s shall apply.

OBJECTIVE

CC.2.1 The objective of the CC is to ensure that by specifying minimum technical, design and operational criteria, the basic rules for connection to the National Electricity Transmission System and (for certain GB Code Users) to a User’s System are similar for all GB Code Users of an equivalent category and will enable The Company to comply with its statutory and Transmission Licence obligations.

CC.2.2 In the case of any OTSDUW, the objective of the CC is to ensure that by specifying the minimum technical, design and operational criteria, the basic rules relating to an Offshore Transmission System designed and constructed by an Offshore Transmission Licensee or designed and/or constructed by an GB Code User under the OTSDUW Arrangements are equivalent.

CC.2.3 Provisions of the CC which apply in relation to OTSDUW and OTSUA, and/or a Transmission Interface Site, shall (in any particular case) apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply, without prejudice to the continuing application of provisions of the CC applying in relation to the relevant Offshore Transmission System and/or Connection Site. It is the case therefore that in cases where the OTSUA becomes operational prior to the OTSUA Transfer Time that a GB Generator is required to comply with this CC both as it applies to its Plant and Apparatus at a Connection Site/Connection Point and the OTSUA at the Transmission Interface Site/Transmission Interface Point until the OTSUA Transfer Time and this CC shall be construed accordingly.

CC.2.4 In relation to OTSDUW, provisions otherwise to be contained in a Bilateral Agreement may be contained in the Construction Agreement, and accordingly a reference in the CC to a relevant Bilateral Agreement includes the relevant Construction Agreement.

SCOPE

CC.3.1 The CC applies to The Company and to GB Code Users, which in the CC means:

(a) GB Generators (other than those which only have Embedded Small Power Stations), including those undertaking OTSDUW;

(b) Network Operators;

(c) Non-Embedded Customers;
(d) **DC Converter Station** owners; and
(e) **BM Participants** and **Externally Interconnected System Operators** in respect of CC.6.5 only.

**CC.3.2** The above categories of **GB Code User** will become bound by the **CC** prior to them generating, distributing, supplying or consuming, as the case may be, and references to the various categories should, therefore, be taken as referring to them in that prospective role as well as to **GB Code Users** actually connected.

**CC.3.3** **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded DC Converter Stations** not subject to a **Bilateral Agreement** Provisions.

The following provisions apply in respect of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded DC Converter Stations** not subject to a **Bilateral Agreement**.

**CC.3.3.1** The obligations within the **CC** that are expressed to be applicable to **GB Generators** in respect of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **DC Converter Station Owners** in respect of **Embedded DC Converter Stations** not subject to a **Bilateral Agreement** (where the obligations are in each case listed in CC.3.3.2) shall be read and construed as obligations that the **Network Operator** within whose **System** any such **Medium Power Station** or **DC Converter Station** is **Embedded** must ensure are performed and discharged by the **GB Generator** or the **DC Converter Station owner**. **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded DC Converter Stations** not subject to a **Bilateral Agreement** which are located **Offshore** and which are connected to an **Onshore GB Code Users System** will be required to meet the applicable requirements of the Grid Code as though they are an **Onshore GB Generator** or **Onshore DC Converter Station Owner** connected to an **Onshore User System Entry Point**.

**CC.3.3.2** The **Network Operator** within whose **System** a **Medium Power Station** not subject to a **Bilateral Agreement** is **Embedded** or a **DC Converter Station** not subject to a **Bilateral Agreement** is **Embedded** must ensure that the following obligations in the **CC** are performed and discharged by the **GB Generator** or the **DC Converter Station owner**:  

CC.5.1
CC.5.2.2
CC.5.3
CC.6.1.3
CC.6.1.5 (b)
CC.6.3.2, CC.6.3.3, CC.6.3.4, CC.6.3.6, CC.6.3.7, CC.6.3.8, CC.6.3.9, CC.6.3.10, CC.6.3.12, CC.6.3.13, CC.6.3.15, CC.6.3.16
CC.6.4.4
CC.6.5.6 (where required by CC.6.4.4)

In respect of CC.6.2.2.2, CC.6.2.2.3, CC.6.2.2.5, CC.6.1.5(a), CC.6.1.5(b) and CC.6.3.11 equivalent provisions as co-ordinated and agreed with the **Network Operator** and **GB Generator** or **DC Converter Station owner** may be required. Details of any such requirements will be notified to the **Network Operator** in accordance with CC.3.5.

**CC.3.3.3** In the case of **Embedded Medium Power Stations** not subject to a **Bilateral Agreement** and **Embedded DC Converter Stations** not subject to a **Bilateral Agreement** the requirements in:

CC.6.1.6
that would otherwise have been specified in a **Bilateral Agreement** will be notified to the relevant **Network Operator** in writing in accordance with the provisions of the **CUSC** and the **Network Operator** must ensure such requirements are performed and discharged by the **GB Generator** or the **DC Converter Station** owner.

**CC.3.4**

In the case of **Offshore Embedded Power Stations** connected to an **Offshore GB Code User’s System** which directly connects to an **Offshore Transmission System**, any additional requirements in respect of such **Offshore Embedded Power Stations** may be specified in the relevant **Bilateral Agreement** with the **Network Operator** or in any **Bilateral Agreement** between **The Company** and such **Offshore Embedded Power Station**.

**CC.3.5**

In the case of a **GB Generator** undertaking **OTSDUW** connecting to an **Onshore Network Operator’s System**, any additional requirements in respect of such **OTSDUW Plant and Apparatus** will be specified in the relevant **Bilateral Agreement** with the **GB Generator**. For the avoidance of doubt, requirements applicable to **GB Generators** undertaking **OTSDUW** and connecting to a **Network Operator’s System**, shall be consistent with those applicable requirements of **GB Generators** undertaking **OTSDUW** and connecting to a **Transmission Interface Point**.

**CC.4**

**PROCEDURE**

**CC.4.1**

The **CUSC** contains certain provisions relating to the procedure for connection to the **National Electricity Transmission System** or, in the case of **Embedded Power Stations** or **Embedded DC Converter Stations**, becoming operational and includes provisions relating to certain conditions to be complied with by **GB Code Users** prior to and during the course of **The Company** notifying the GB Code User that it has the right to become operational. The procedure for a **GB Code User** to become connected is set out in the **Compliance Processes**.

**CC.5**

**CONNECTION**

**CC.5.1**

The provisions relating to connecting to the **National Electricity Transmission System** (or to a **User’s System** in the case of a connection of an **Embedded Large Power Station** or **Embedded Medium Power Station** or **Embedded DC Converter Station**) are contained in:

(a) the **CUSC** and/or **CUSC Contract** (or in the relevant application form or offer for a **CUSC Contract**);

(b) or, in the case of an **Embedded Development**, the relevant **Distribution Code** and/or the **Embedded Development Agreement** for the connection (or in the relevant application form or offer for an **Embedded Development Agreement**),

and include provisions relating to both the submission of information and reports relating to compliance with the relevant **Connection Conditions** for that **GB Code User**, **Safety Rules**, commissioning programmes, **Operation Diagrams** and approval to connect (and their equivalents 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**). References in the **CC** to the “**Bilateral Agreement**” and/or “**Construction Agreement**” and/or “**Embedded Development Agreement**” shall be deemed to include references to the application form or offer therefor.

**CC.5.2**

**Items For Submission**
Prior to the Completion Date (or, where the GB Generator is undertaking OTSDUW, any later date specified) under the Bilateral Agreement and/or Construction Agreement, the following is submitted pursuant to the terms of the Bilateral Agreement and/or Construction Agreement:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) copies of all Safety Rules and Local Safety Instructions applicable at Users' Sites which will be used at the Transmission/User interface (which, for the purpose of OC8, must be to The Company's satisfaction regarding the procedures for Isolation and Earthing. The Company will consult the Relevant Transmission Licensee when determining whether the procedures for Isolation and Earthing are satisfactory);

(d) information to enable the preparation of the Site Responsibility Schedules on the basis of the provisions set out in Appendix 1;

(e) an Operation Diagram for all HV Apparatus on the User side of the Connection Point as described in CC.7;

(f) the proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

(g) written confirmation that Safety Co-ordinators acting on behalf of the User are authorised and competent pursuant to the requirements of OC8;

(h) Such RISSP prefixes pursuant to the requirements of OC8. Prefixes shall be circulated utilising a proforma in accordance with OC8;

(i) a list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorised to make binding decisions on behalf of the User, pursuant to OC9;

(j) a list of managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User;

(k) information to enable the preparation of the Site Common Drawings as described in CC.7;

(l) a list of the telephone numbers for the Users facsimile machines referred to in CC.6.5.9; and

(m) for Sites in Scotland and Offshore a list of persons appointed by the User to undertake operational duties on the User's System (including any OTSDUW prior to the OTSUA Transfer Time) and to issue and receive operational messages and instructions in relation to the User's System (including any OTSDUW prior to the OTSUA Transfer Time); and an appointed person or persons responsible for the maintenance and testing of User's Plant and Apparatus.

Prior to the Completion Date the following must be submitted to The Company by the Network Operator in respect of an Embedded Development:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;
(c) the proposed name of the Embedded Medium Power Station or Embedded DC Converter Station Site (which shall be agreed with The Company unless it is the same as, or confusingly similar to, the name of other Transmission Site or User Site);

CC.5.2.3

Prior to the Completion Date contained within an Offshore Transmission Distribution Connection Agreement, the following must be submitted to The Company by the Network Operator in respect of a proposed new Interface Point within its User System:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

CC.5.2.4

In the case of OTSDUW Plant and Apparatus (in addition to items under CC.5.2.1 in respect of the Connection Site), prior to the Completion Date (or any later date specified) under the Construction Agreement the following must be submitted to The Company by the GB Code User in respect of the proposed new Connection Point and Interface Point:

(a) updated Planning Code data (Standard Planning Data, Detailed Planning Data and OTSDUW Data and Information), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in CC.6;

(c) information to enable preparation of the Site Responsibility Schedules at the Transmission Interface Site on the basis of the provisions set out in Appendix 1.

(d) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

CC.5.3

(a) Of the items CC.5.2.1 (c), (e), (g), (h), (k) and (m) need not be supplied in respect of Embedded Power Stations or Embedded DC Converter Stations,

(b) item CC.5.2.1(i) need not be supplied in respect of Embedded Small Power Stations and Embedded Medium Power Stations or Embedded DC Converter Stations with a Registered Capacity of less than 100MW, and

(c) items CC.5.2.1(d) and (j) are only needed in the case where the Embedded Power Station or the Embedded DC Converter Station is within a Connection Site with another User.

CC.6

TECHNICAL, DESIGN AND OPERATIONAL CRITERIA

CC.6.1

National Electricity Transmission System Performance Characteristics

CC.6.1.1

The Company shall ensure that, subject as provided in the Grid Code, the National Electricity Transmission System complies with the following technical, design and operational criteria in relation to the part of the National Electricity Transmission System at the Connection Site with a GB Code User and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point (unless otherwise specified in CC.6) although in relation to operational criteria The Company may be unable (and will not be required) to comply with this obligation to the extent that there are insufficient Power Stations or User Systems are not available, or Users do not comply with The Company’s instructions or otherwise do not comply with the Grid Code and each GB Code User shall ensure that its Plant and Apparatus complies with the criteria set out in CC.6.1.5.
Grid Frequency Variations

CC.6.1.2 The **Frequency** of the **National Electricity Transmission System** shall be nominally 50Hz and shall be controlled within the limits of 49.5 - 50.5Hz unless exceptional circumstances prevail.

CC.6.1.3 The **System Frequency** could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of **GB Code User’s Plant** and **Apparatus** and **OTSDUW Plant and Apparatus** must enable operation of that **Plant** and **Apparatus** within that range in accordance with the following:

<table>
<thead>
<tr>
<th>Frequency Range</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>51.5Hz - 52Hz</td>
<td>Operation for a period of at least 15 minutes is required each time the <strong>Frequency</strong> is above 51.5Hz.</td>
</tr>
<tr>
<td>51Hz - 51.5Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the <strong>Frequency</strong> is above 51Hz.</td>
</tr>
<tr>
<td>49.0Hz - 51Hz</td>
<td>Continuous operation is required</td>
</tr>
<tr>
<td>47.5Hz - 49.0Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the <strong>Frequency</strong> is below 49.0Hz.</td>
</tr>
<tr>
<td>47Hz - 47.5Hz</td>
<td>Operation for a period of at least 20 seconds is required each time the <strong>Frequency</strong> is below 47.5Hz.</td>
</tr>
</tbody>
</table>

For the avoidance of doubt, disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz, unless agreed with **The Company** in accordance with CC.6.3.12.

Grid Voltage Variations

CC.6.1.4 Subject as provided below, the voltage on the 400kV part of the **National Electricity Transmission System** at each **Connection Site** with a **GB Code User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within ±5% of the nominal value unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail. Voltages on the 275kV and 132kV parts of the **National Electricity Transmission System** at each **Connection Site** with a **User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail. At nominal **System** voltages below 132kV the voltage of the **National Electricity Transmission System** at each **Connection Site** with a **User** (and in the case of **OTSDUW Plant and Apparatus**, a **Transmission Interface Point**) will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, voltage may collapse transiently to zero at the point of fault until the fault is cleared. The normal operating ranges of the **National Electricity Transmission System** are summarised below:

<table>
<thead>
<tr>
<th>National Electricity Transmission System</th>
<th>Normal Operating Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal Voltage</td>
<td></td>
</tr>
<tr>
<td>400kV</td>
<td>400kV ±5%</td>
</tr>
<tr>
<td>275kV</td>
<td>275kV ±10%</td>
</tr>
<tr>
<td>132kV</td>
<td>132kV ±10%</td>
</tr>
</tbody>
</table>

**The Company** and a **GB Code User** may agree greater or lesser variations in voltage to those set out above in relation to a particular **Connection Site**, and insofar as a greater or lesser variation is agreed, the relevant figure set out above shall, in relation to that **GB Code User** at the particular **Connection Site**, be replaced by the figure agreed.
Voltage Waveform Quality

**CC.6.1.5**

All **Plant** and **Apparatus** connected to the **National Electricity Transmission System**, and that part of the **National Electricity Transmission System** at each **Connection Site** or, in the case of **OTSDUW Plant and Apparatus**, at each **Interface Point**, should be capable of withstanding the following distortions of the voltage waveform in respect of harmonic content and phase unbalance:

(a) **Harmonic Content**

The **Electromagnetic Compatibility Levels** for harmonic distortion on the **Onshore Transmission System** from all sources under both **Planned Outage** and fault outage conditions, (unless abnormal conditions prevail) shall comply with **Engineering Recommendation G5**. The **Electromagnetic Compatibility Levels** for harmonic distortion on an **Offshore Transmission System** will be defined in relevant **Bilateral Agreements**.

**Engineering Recommendation G5** contains planning criteria which **The Company** will apply to the connection of non-linear **Load** to the **National Electricity Transmission System**, which may result in harmonic emission limits being specified for these **Loads** in the relevant **Bilateral Agreement**. The application of the planning criteria will take into account the position of **GB Code Users'** and **EU Code Users' Plant and Apparatus** (and **OTSDUW Plant and Apparatus**) in relation to harmonic emissions. **GB Code Users** must ensure that connection of distorting loads to their **User Systems** do not cause any harmonic emission limits specified in the **Bilateral Agreement**, or where no such limits are specified, the relevant planning levels specified in **Engineering Recommendation G5** to be exceeded.

(b) **Phase Unbalance**

Under **Planned Outage** conditions, the weekly 95 percentile of **Phase (Voltage) Unbalance**, calculated in accordance with IEC 61000-4-30 and IEC 61000-3-13, on the **National Electricity Transmission System** for voltages above 150kV should remain, in England and Wales, below 1.5%, and in Scotland, below 2%, and for voltages of 150kV and below, across GB below 2%, unless abnormal conditions prevail and **Offshore** (or in the case of **OTSDUW, OTSDUW Plant and Apparatus**) will be defined in relevant **Bilateral Agreements**.

The **Phase (Voltage) Unbalance** is calculated from the ratio of root mean square (rms) of negative phase sequence voltage to rms of positive phase sequence voltage, based on 10-minute average values, in accordance with IEC 61000-4-30.

**CC.6.1.6**

Across GB, under the **Planned Outage** conditions stated in CC.6.1.5(b) infrequent short duration peaks with a maximum value of 2% are permitted for **Phase (Voltage) Unbalance**, for voltages above 150kV, subject to the prior agreement of **The Company** under the **Bilateral Agreement** and in relation to **OTSDUW**, the **Construction Agreement**. **The Company** will only agree following a specific assessment of the impact of these levels on **Transmission Apparatus** and other **Users Apparatus** with which it is satisfied.

Voltage Fluctuations

**CC.6.1.7** Voltage changes at a **Point of Common Coupling** on the **Onshore Transmission System** shall not exceed:

(a) The limits specified in Table CC.6.1.7(a) with the stated frequency of occurrence, where:

(i)

\[ \%\Delta V_{\text{steady state}} = 100 \times \frac{\Delta V_{\text{steady state}}}{V_n} \]

and

\[ \%\Delta V_{\text{max}} = 100 \times \frac{\Delta V_{\text{max}}}{V_n} \]
(ii) $V_n$ is the nominal system voltage;

(iii) $V_{\text{steady state}}$ is the voltage at the end of a period of 1 s during which the rate of change of system voltage over time is $\leq 0.5\%$;

(iv) $\Delta V_{\text{steady state}}$ is the difference in voltage between the initial steady state voltage prior to the RVC ($V_0$) and the final steady state voltage after the RVC ($V'_0$);

(v) $\Delta V_{\text{max}}$ is the absolute change in the system voltage relative to the initial steady state system voltage ($V_0$);

(vi) All voltages are the r.m.s. of the voltage measured over one cycle refreshed every half a cycle as per BS EN 61000-3-30; and

(vii) The applications in the ‘Example Applicability’ column are examples only and are not definitive.

<table>
<thead>
<tr>
<th>Category</th>
<th>Title</th>
<th>Maximum number of occurrence</th>
<th>Limits</th>
<th>Example Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Frequent events</td>
<td>(see NOTE 1)</td>
<td>As per Figure CC.6.1.7 (1)</td>
<td>Any single or repetitive RVC that falls inside Figure CC.6.1.7 (1)</td>
</tr>
<tr>
<td>2</td>
<td>Infrequent events</td>
<td>4 events in 1 calendar month (see NOTE 2)</td>
<td>As per Figure CC.6.1.7 (2)</td>
<td>Infrequent motor starting, transformer energisation, re-energisation (see NOTE 7)</td>
</tr>
<tr>
<td>3</td>
<td>Very infrequent events</td>
<td>1 event in 3 calendar months (see NOTE 2)</td>
<td>As per Figure CC.6.1.7 (3)</td>
<td>Commissioning, maintenance &amp; post fault switching (see NOTE 7)</td>
</tr>
</tbody>
</table>

**NOTE 1:** ±6% is permissible for 100 ms reduced to ±3% thereafter as per Figure CC.6.1.7 (1).
If the profile of repetitive voltage change(s) falls within the envelope given in Figure CC.6.1.7 (1), the assessment of such voltage change(s) shall be undertaken according to the recommendations for assessment of flicker and shall conform to the planning levels provided for flicker.
If any part of the voltage change(s) falls outside the envelope given in Figure CC.6.1.7 (1), the assessment of such voltage changes, repetitive or not, shall be done according to the guidance and limits for RVCs.

**NOTE 2:** No more than 1 event is permitted per day, consisting of up to 4 RVCs, each separated by at least 10 minutes with all switching completed within a two-hour window.

**NOTE 3:** −10% is permissible for 100 ms reduced to −6% until 2 s then reduced to −3% thereafter as per Figure CC.6.1.7 (2).
Table CC.6.1.7 (a) – Planning levels for RVC

(b) The voltage change limit is the absolute maximum allowed of either the phase-to-earth voltage change or the phase-to-phase voltage change, whichever is the highest. The limits do not apply to single phasor equivalent voltages, e.g. positive phase sequence (PPS) voltages. For high impedance earthed systems, the maximum phase-to-phase, i.e. line voltage, should be used for assessment.

(c) The RVCs in Category 2 and 3 should not exceed the limits depicted in the time dependent characteristic shown in Figure CC.6.1.7 (2) and Figure CC.6.1.7 (3) respectively. These limits do not apply to: 1) fault clearance operations; or 2) immediate operations in response to fault conditions; or 3) operations relating to post fault system restoration (for the avoidance of doubt this third exception pertains to a fault that is external to the Users Plant and Apparatus).

(d) Any RVCs permitted in Category 2 and Category 3 should be at least 10 minutes apart.

(e) The value of $V_{\text{steady state}}$ should be established immediately prior to the start of a RVC. Following a RVC, the voltage should remain within the relevant envelope, as shown in Figures CC.6.1.7 (1), CC.6.1.7 (2), CC.6.1.7 (3), until a $V_{\text{steady state}}$ condition has been satisfied.

![Figure CC.6.1.7 (1) — Voltage characteristic for frequent events](image-url)
(f) The voltage change between two steady state voltage conditions should not exceed 3%. (The limit is based on 3% of the nominal voltage of the system (\(V_n\)) as measured at the Point of Common Coupling. The step voltage change as measured at the customer's supply terminals or equipment terminals could be greater. For example: The step voltage change limit stated in BS EN 61000-3-3 and BS EN 61000-3-11 is 3.3% when measured at the equipment terminals.)

(g) The limits apply to voltage changes measured at the Point of Common Coupling.

(h) Category 3 events that are planned should be notified to The Company in advance.
(i) For connections with a **Completion Date** after 1st September 2015 and where voltage changes would constitute a risk to the **National Electricity Transmission System** or, in **The Company’s** view, the **System** of any **GB Code User, Bilateral Agreements** may include provision for **The Company** to reasonably limit the number of voltage changes in Category 2 or 3 to a lower number than specified in Table CC.6.1.7(a) to ensure that the total number of voltage changes at the **Point of Common Coupling** across multiple **Users** remains within the limits of Table CC.6.1.7(a).

(j) The planning levels applicable to **Flicker Severity Short Term** (Pst) and **Flicker Severity Long Term** (Plt) are set out in Table CC.6.1.7(b).

<table>
<thead>
<tr>
<th>Supply system Nominal voltage</th>
<th>Planning level</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Flicker Severity Short Term (Pst)</td>
</tr>
<tr>
<td>3.3 kV, 6.6 kV, 11 kV, 20 kV, 33 kV</td>
<td>0.9</td>
</tr>
<tr>
<td>66 kV, 110 kV, 132 kV, 150 kV, 200 kV, 220 kV, 275 kV, 400 kV</td>
<td>0.8</td>
</tr>
</tbody>
</table>

**NOTE 1:** The magnitude of $P_{st}$ is linear with respect to the magnitude of the voltage changes giving rise to it.

**NOTE 2:** Extreme caution is advised in allowing any excursions of $P_{st}$ and $P_{lt}$ above the planning level.

**Table CC.6.7.1(b) — Planning levels for flicker**

The values and figures referred to in this paragraph CC.6.1.7 are derived from Engineering Recommendation P28 Issue 2.

**CC.6.1.8** Voltage fluctuations at a **Point of Common Coupling** with a fluctuating **Load** directly connected to an **Offshore Transmission System** (or in the case of **OTSDUW, OTSDUW Plant and Apparatus**) shall not exceed the limits set out in the **Bilateral Agreement**.

**Sub-Synchronous Resonance and Sub-Synchronous Torsional Interaction**

**CC.6.1.9** **The Company** shall ensure that **GB Code Users’ Plant and Apparatus** will not be subject to unacceptable Sub-Synchronous Oscillation conditions as specified in the relevant **Licence Standards**.

**CC.6.1.10** **The Company** shall ensure where necessary, and in consultation with **Relevant Transmission Licensees** where required, that any relevant site specific conditions applicable at a **GB Code User’s Connection Site**, including a description of the Sub-Synchronous Oscillation conditions considered in the application of the relevant **License Standards**, are set out in the **GB Code User’s Bilateral Agreement**.
The following requirements apply to Plant and Apparatus relating to the Connection Point, and OTSDUW Plant and Apparatus relating to the Interface Point (until the OTSUA Transfer Time) and Connection Point which (except as otherwise provided in the relevant paragraph) each GB Code User must ensure are complied with in relation to its Plant and Apparatus and which in the case of CC.6.2.2.2.2, CC.6.2.3.1.1 and CC.6.2.1.1(b) only, The Company must ensure are complied with in relation to Transmission Plant and Apparatus, as provided in those paragraphs.

CC.6.2.1 General Requirements

CC.6.2.1.1 (a) The design of connections between the National Electricity Transmission System and:

(i) any Generating Unit (other than a CCGT Unit or Power Park Unit), DC Converter, Power Park Module or CCGT Module, or

(ii) any Network Operator’s System, or

(iii) Non-Embedded Customers equipment;

will be consistent with the Licence Standards.

In the case of OTSDUW, the design of the OTSUA’s connections at the Interface Point and Connection Point will be consistent with Licence Standards.

(b) The National Electricity Transmission System (and any OTSDUW Plant and Apparatus) at nominal System voltages of 132kV and above is/shall be designed to be earthed with an Earth Fault Factor of, in England and Wales or Offshore, below 1.4 and in Scotland, below 1.5. Under fault conditions the rated Frequency component of voltage could fall transiently to zero on one or more phases or, in England and Wales, rise to 140% phase-to-earth voltage, or in Scotland, rise to 150% phase-to-earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase-to-earth.

(c) For connections to the National Electricity Transmission System at nominal System voltages of below 132kV the earthing requirements and voltage rise conditions will be advised by The Company as soon as practicable prior to connection and in the case of OTSDUW Plant and Apparatus shall be advised to The Company by the GB Code User.

CC.6.2.1.2 Substation Plant and Apparatus

(a) The following provisions shall apply to all Plant and Apparatus which is connected at the voltage of the Connection Point (and OTSDUW Plant and Apparatus at the Interface Point) and which is contained in equipment bays that are within the Transmission busbar Protection zone at the Connection Point. This includes circuit breakers, switch disconnectors, disconnectors, Earthing Devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination devices. Where necessary, this is as more precisely defined in the Bilateral Agreement.

(i) Plant and/or Apparatus prior to 1st January 1999

Each item of such Plant and/or Apparatus which at 1st January 1999 is either:

installed; or

owned (but is either in storage, maintenance or awaiting installation); or ordered;

and is the subject of a Bilateral Agreement with regard to the purpose for which it is in use or intended to be in use, shall comply with the relevant standards/specifications applicable at the time that the Plant and/or Apparatus was
designed (rather than commissioned) and any further requirements as specified in the Bilateral Agreement.

(ii) **Plant and/or Apparatus post 1st January 1999 for a new Connection Point (including OTSDUW Plant and Apparatus at the Interface Point)**

Each item of such Plant and/or Apparatus installed in relation to a new Connection Point (or OTSDUW Plant and Apparatus at the Interface Point) after 1st January 1999 shall comply with the relevant Technical Specifications and any further requirements identified by The Company, acting reasonably, to reflect the options to be followed within the Technical Specifications and/or to complement if necessary the Technical Specifications so as to enable The Company to comply with its obligations in relation to the National Electricity Transmission System or the Relevant Transmission Licensee to comply with its obligations in relation to its Transmission System. This information, including the application dates of the relevant Technical Specifications, will be as specified in the Bilateral Agreement.

(iii) **New Plant and/or Apparatus post 1st January 1999 for an existing Connection Point (including OTSDUW Plant and Apparatus at the Interface Point)**

Each new additional and/or replacement item of such Plant and/or Apparatus installed in relation to a change to an existing Connection Point (or OTSDUW Plant and Apparatus at the Interface Point and Connection Point) after 1st January 1999 shall comply with the standards/specifications applicable when the change was designed, or such other standards/specifications as necessary to ensure that the item of Plant and/or Apparatus is reasonably fit for its intended purpose having due regard to the obligations of The Company, the relevant GB Code User and the Relevant Transmission Licensee under their respective Licences. Where appropriate this information, including the application dates of the relevant standards/specifications, will be as specified in the varied Bilateral Agreement.

(iv) **Used Plant and/or Apparatus being moved, re-used or modified**

If, after its installation, any such item of Plant and/or Apparatus is subsequently:

- moved to a new location; or
- used for a different purpose; or
- otherwise modified;

then the standards/specifications as described in (i), (ii), or (iii) above or in ECC.6.2.1.2 (as applicable) will apply as appropriate to such Plant and/or Apparatus, which must be reasonably fit for its intended purpose having due regard to the obligations of The Company, the relevant GB Code User and the Relevant Transmission Licensee under their respective Licences.

(b) **The Company** shall at all times maintain a list of those Technical Specifications and additional requirements which might be applicable under this CC.6.2.1.2 and which may be referenced by The Company in the Bilateral Agreement. The Company shall provide a copy of the list upon request to any User.

(c) Where the GB Code User provides The Company with information and/or test reports in respect of Plant and/or Apparatus which the GB Code User reasonably believes demonstrate the compliance of such items with the provisions of a Technical Specification, then The Company shall promptly and without unreasonable delay give due and proper consideration to such information.

(d) **Plant and Apparatus** shall be designed, manufactured and tested in premises with an accredited certificate in accordance with the quality assurance requirements of the relevant standard in the BS EN ISO 9000 series (or equivalent as reasonably approved by The Company) or in respect of test premises which do not include a manufacturing facility premises with an accredited certificate in accordance with BS EN 45001.
(e) Each connection between an **GB Code User** and the **National Electricity Transmission System** must be controlled by a circuit-breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the point of connection. The **Seven Year Statement** gives values of short circuit current and the rating of **Transmission** circuit breakers at existing and committed **Connection Points** for future years.

(f) Each connection between a **GB Generator** undertaking OTSDUW or an **Onshore Transmission Licensee**, must be controlled by a circuit breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the **Transmission Interface Point**. The **Seven Year Statement** gives values of short circuit current and the rating of **Transmission** circuit breakers at existing and committed **Transmission Interface Points** for future years.

**CC.6.2.2 Requirements at Connection Points or, in the case of OTSDUW at Interface Points that relate to GB Generators or OTSDUW Plant and Apparatus or DC Converter Station owners**

**CC.6.2.2.1 Not Used.**

**CC.6.2.2.2 Generating Unit, OTSDUW Plant and Apparatus and Power Station Protection Arrangements**

**CC.6.2.2.2.1 Minimum Requirements**

Protection of Generating Units (other than **Power Park Units**), **DC Converters**, **OTSDUW Plant and Apparatus** or **Power Park Modules** and their connections to the **National Electricity Transmission System** shall meet the requirements given below. These are necessary to reduce the impact on the **National Electricity Transmission System** of faults on **OTSDUW Plant and Apparatus** circuits or circuits owned by **GB Generators** or **DC Converter Station** owners.

**CC.6.2.2.2 Fault Clearance Times**

(a) The required fault clearance time for faults on the **GB Generator's** or **DC Converter Station** owner's equipment directly connected to the **National Electricity Transmission System** or **OTSDUW Plant and Apparatus** and for faults on the **National Electricity Transmission System** directly connected to the **GB Generator** or **DC Converter Station** owner's equipment or **OTSDUW Plant and Apparatus**, from fault inception to the circuit breaker arc extinction, shall be set out in the **Bilateral Agreement**. The fault clearance time specified in the **Bilateral Agreement** shall not be shorter than the durations specified below:

(i) 80ms at 400kV  
(ii) 100ms at 275kV  
(iii) 120ms at 132kV and below  

but this shall not prevent the **GB Code User** or the **Relevant Transmission Licensee** or the **GB Generator** (including in respect of **OTSDUW Plant and Apparatus**) from selecting a shorter fault clearance time on their own Plant and Apparatus provided **Discrimination** is achieved.

A longer fault clearance time may be specified in the **Bilateral Agreement** for faults on the **National Electricity Transmission System**. A longer fault clearance time for faults on the **GB Generator** or **DC Converter Station** owner’s equipment or **OTSDUW Plant and Apparatus** may be agreed with **The Company** in accordance with the terms of the **Bilateral Agreement** but only if System requirements, in the **Company’s** view, permit. The probability that the fault clearance time stated in the **Bilateral Agreement** will be exceeded by any given fault, must be less than 2%.
In the event that the required fault clearance time is not met as a result of failure to operate on the Main Protection System(s) provided, GB Generators or DC Converter Station owners or GB Generators in the case of OTSDUW Plant and Apparatus shall, except as specified below provide Independent Back-Up Protection. The Relevant Transmission Licensee will also provide Back-Up Protection; and the Relevant Transmission Licensee’s and the GB Code User’s Back-Up Protections will be co-ordinated so as to provide Discrimination.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus in respect of which the Completion Date is after 20 January 2016 and connected to the National Electricity Transmission System at 400kV or 275kV and where two Independent Main Protections are provided to clear faults on the HV Connections within the required fault clearance time, the Back-Up Protection provided by GB Generators (including in respect of OTSDUW Plant and Apparatus) and DC Converter Station owner shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections. Where two Independent Main Protections are installed, the Back-Up Protection may be integrated into one (or both) of the Independent Main Protection relays.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus in respect of which the Completion Date is after 20 January 2016 and connected to the National Electricity Transmission System at 132 kV and where only one Main Protection is provided to clear faults on the HV Connections within the required fault clearance time, the Independent Back-Up Protection provided by the GB Generator (including in respect of OTSDUW Plant and Apparatus) and the DC Converter Station owner shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections.

On a Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus connected to the National Electricity Transmission System and on Generating Units (other than a Power Park Unit), DC Converters or Power Park Modules or OTSDUW Plant and Apparatus connected to the National Electricity Transmission System at 400 kV or 275 kV or 132 kV, in respect of which the Completion Date is before the 20 January 2016, the Back-Up Protection or Independent Back-Up Protection shall operate to give a fault clearance time of no longer than 800ms in England and Wales or 300ms in Scotland at the minimum infeed for normal operation for faults on the HV Connections.

A Generating Unit (other than a Power Park Unit), DC Converter or Power Park Module or OTSDUW Plant and Apparatus) with Back-Up Protection or Independent Back-Up Protection will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the National Electricity Transmission System by breaker fail Protection at 400kV or 275kV or of a fault cleared by Back-Up Protection where the GB Generator (including in the case of OTSDUW Plant and Apparatus) or DC Converter is connected at 132kV and below. This will permit Discrimination between GB Generator in respect of OTSDUW Plant and Apparatus or DC Converter Station owners’ Back-Up Protection or Independent Back-Up Protection and the Back-Up Protection provided on the National Electricity Transmission System and other Users’ Systems.
(c) When the Generating Unit (other than Power Park Units), or the DC Converter or Power Park Module or OTSDUW Plant and Apparatus is connected to the National Electricity Transmission System at 400kV or 275kV, and in Scotland and Offshore also at 132kV, and a circuit breaker is provided by the GB Generator (including in respect of OTSDUW Plant and Apparatus) or the DC Converter Station owner, or the Relevant Transmission Licensee, as the case may be, to interrupt fault current interchange with the National Electricity Transmission System, or GB Generator’s System, or DC Converter Station owner’s System, as the case may be, circuit breaker fail Protection shall be provided by the GB Generator (including in respect of OTSDUW Plant and Apparatus) or DC Converter Station owner, or the Relevant Transmission Licensee as the case may be, on this circuit breaker. In the event, following operation of a Protection system, of a failure to interrupt fault current by these circuit-breakers within the Fault Current Interruption Time, the circuit breaker fail Protection is required to initiate tripping of all the necessary electrically adjacent circuit-breakers so as to interrupt the fault current within the next 200ms.

(d) The target performance for the System Fault Dependability Index shall be not less than 99%. This is a measure of the ability of Protection to initiate successful tripping of circuit breakers which are associated with the faulty item of Apparatus.

CC.6.2.2.3 Equipment to be provided

CC.6.2.2.3.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement. In this CC, the term “interconnecting connections” means the primary conductors from the current transformer accommodation on the circuit side of the circuit breaker to the Connection Point or the primary conductors from the current transformer accommodation on the circuit side of the OTSDUW Plant and Apparatus of the circuit breaker to the Transmission Interface Point.

CC.6.2.2.3.2 Circuit-breaker fail Protection

The GB Generator or DC Converter Station owner will install circuit breaker fail Protection equipment in accordance with the requirements of the Bilateral Agreement. The GB Generator or DC Converter Station owner will also provide a back-trip signal in the event of loss of air from its pressurised head circuit breakers, during the Generating Unit (other than a CCGT Unit or Power Park Unit) or CCGT Module or DC Converter or Power Park Module run-up sequence, where these circuit breakers are installed.

CC.6.2.2.3.3 Loss of Excitation

The GB Generator must provide Protection to detect loss of excitation on a Generating Unit and initiate a Generating Unit trip.

CC.6.2.2.3.4 Pole-Slapping Protection

Where, in The Company’s reasonable opinion, System requirements dictate, The Company will specify in the Bilateral Agreement a requirement for GB Generators to fit pole-slipping Protection on their Generating Units.

CC.6.2.2.3.5 Signals for Tariff Metering

GB Generators and DC Converter Station owners will install current and voltage transformers supplying all tariff meters at a voltage to be specified in, and in accordance with, the Bilateral Agreement.

CC.6.2.2.4 Work on Protection Equipment
No busbar Protection, mesh corner Protection, circuit-breaker fail Protection relays, AC or DC wiring (other than power supplies or DC tripping associated with the Generating Unit, DC Converter or Power Park Module itself) may be worked upon or altered by the GB Generator or DC Converter Station owner personnel in the absence of a representative of the Relevant Transmission Licensee, or written authority from the Relevant Transmission Licensee to perform such work or alterations in the absence of a representative of the Relevant Transmission Licensee.

CC.6.2.2.5 Relay Settings

Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement and in relation to OTSDUW Plant and Apparatus, across the Interface Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

CC.6.2.3 Requirements at Connection Points relating to Network Operators and Non-Embedded Customers

CC.6.2.3.1 Protection Arrangements for Network Operators and Non-Embedded Customers

CC.6.2.3.1.1 Protection of Network Operator and Non-Embedded Customers Systems directly connected to the National Electricity Transmission System, shall meet the requirements given below:

Fault Clearance Times

(a) The required fault clearance time for faults on Network Operator and Non-Embedded Customer equipment directly connected to the National Electricity Transmission System, and for faults on the National Electricity Transmission System directly connected to the Network Operator’s or Non-Embedded Customer’s equipment, from fault inception to the circuit breaker arc extinction, shall be set out in each Bilateral Agreement. The fault clearance time specified in the Bilateral Agreement shall not be shorter than the durations specified below:

(i) 80ms at 400kV
(ii) 100ms at 275kV
(iii) 120ms at 132kV and below

but this shall not prevent the GB Code User or the Relevant Transmission Licensee from selecting a shorter fault clearance time on its own Plant and Apparatus provided Discrimination is achieved.

For the purpose of establishing the Protection requirements in accordance with CC.6.2.3.1.1 only, the point of connection of the Network Operator or Non-Embedded Customer equipment to the National Electricity Transmission System shall be deemed to be the low voltage busbars at a GB Grid Supply Point, irrespective of the ownership of the equipment at the GB Grid Supply Point.

A longer fault clearance time may be specified in the Bilateral Agreement for faults on the National Electricity Transmission System. A longer fault clearance time for faults on the Network Operator and Non-Embedded Customers equipment may be agreed with The Company in accordance with the terms of the Bilateral Agreement but only if System requirements in The Company’s view permit. The probability that the fault clearance time stated in the Bilateral Agreement will be exceeded by any given fault must be less than 2%.

(b) For the event of failure of the Protection systems provided to meet the above fault clearance time requirements, Back-Up Protection shall be provided by the Network Operator or Non-Embedded Customer as the case may be.

(ii) The Relevant Transmission Licensee will also provide Back-Up Protection, which will result in a fault clearance time longer than that specified for the Network Operator or Non-Embedded Customer Back-Up Protection so as to provide Discrimination.
(iii) For connections with the **National Electricity Transmission System** at 132kV and below, it is normally required that the **Back-Up Protection** on the **National Electricity Transmission System** shall discriminate with the **Network Operator** or Non-Embedded Customer’s Back-Up Protection.

(iv) For connections with the **National Electricity Transmission System** at 400kV or 275kV, the **Back-Up Protection** will be provided by the Network Operator or Non-Embedded Customer, as the case may be, with a fault clearance time not longer than 300ms for faults on the Network Operator’s or Non-Embedded Customer’s Apparatus.

(v) Such **Protection** will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the **National Electricity Transmission System** by breaker fail **Protection** at 400kV or 275kV. This will permit **Discrimination** between Network Operator’s Back-Up Protection or Non-Embedded Customer’s Back-Up Protection, as the case may be, and Back-Up Protection provided on the **National Electricity Transmission System** and other User Systems. The requirement for and level of **Discrimination** required will be specified in the **Bilateral Agreement**.

(c) (i) Where the **Network Operator** or Non-Embedded Customer is connected to the **National Electricity Transmission System** at 400kV or 275kV, and in Scotland also at 132kV, and a circuit breaker is provided by the Network Operator or Non-Embedded Customer, or the Relevant Transmission Licensee, as the case may be, to interrupt the interchange of fault current with the **National Electricity Transmission System** or the **System** of the Network Operator or Non-Embedded Customer, as the case may be, circuit breaker fail **Protection** will be provided by the Network Operator or Non-Embedded Customer, or the Relevant Transmission Licensee, as the case may be, on this circuit breaker.

(ii) In the event, following operation of a **Protection** system, of a failure to interrupt fault current by these circuit-breakers within the Fault Current Interruption Time, the circuit breaker fail **Protection** is required to initiate tripping of all the necessary electrically adjacent circuit-breakers so as to interrupt the fault current within the next 200ms.

(d) The target performance for the **System Fault Dependability Index** shall be not less than 99%. This is a measure of the ability of **Protection** to initiate successful tripping of circuit breakers which are associated with the faulty items of **Apparatus**.
CC.6.2.3.2 Fault Disconnection Facilities

(a) Where no Transmission circuit breaker is provided at the GB Code User's connection voltage, the GB Code User must provide The Company with the means of tripping all the GB Code User's circuit breakers necessary to isolate faults or System abnormalities on the National Electricity Transmission System. In these circumstances, for faults on the GB Code User's System, the GB Code User's Protection should also trip higher voltage Transmission circuit breakers. These tripping facilities shall be in accordance with the requirements specified in the Bilateral Agreement.

(b) The Company may require the installation of a System to Generator Operational Intertripping Scheme in order to enable the timely restoration of circuits following power System fault(s). These requirements shall be set out in the relevant Bilateral Agreement.

CC.6.2.3.3 Automatic Switching Equipment

Where automatic reclosure of Transmission circuit breakers is required following faults on the GB Code User's System, automatic switching equipment shall be provided in accordance with the requirements specified in the Bilateral Agreement.

CC.6.2.3.4 Relay Settings

Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

CC.6.2.3.5 Work on Protection equipment

Where a Transmission Licensee owns the busbar at the Connection Point, no busbar Protection, mesh corner Protection relays, AC or DC wiring (other than power supplies or DC tripping associated with the Network Operator or Non-Embedded Customer's Apparatus itself) may be worked upon or altered by the Network Operator or Non-Embedded Customer personnel in the absence of a representative of the Relevant Transmission Licensee or written authority from the Relevant Transmission Licensee to perform such work or alterations in the absence of a representative of the Relevant Transmission Licensee.

CC.6.2.3.6 Equipment to be provided

CC.6.2.3.6.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement.

CC.6.3 GENERAL GENERATING UNIT (AND OTSDUW) REQUIREMENTS

CC.6.3.1 This section sets out the technical and design criteria and performance requirements for Generating Units, DC Converters and Power Park Modules (whether directly connected to the National Electricity Transmission System or Embedded) and (where provided in this section) OTSDUW Plant and Apparatus which each GB Generator or DC Converter Station owner must ensure are complied with in relation to its Generating Units, DC Converters and Power Park Modules and OTSDUW Plant and Apparatus but does not apply to Small Power Stations or individually to Power Park Units. References to Generating Units, DC Converters and Power Park Modules in this CC.6.3 should be read accordingly. The performance requirements that OTSDUW Plant and Apparatus must be capable of providing at the Interface Point under this section may be provided using a combination of GB Generator Plant and Apparatus and/or OTSDUW Plant and Apparatus.

Plant Performance Requirements
CC.6.3.2 (a) When supplying **Rated MW** all **Onshore Synchronous Generating Units** must be 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 other than **Rated MW**, all **Onshore Synchronous Generating Units** must be capable of continuous operation at any point between the **Reactive Power** capability limits identified on the **Generator Performance Chart**.

In addition to the above paragraph, where **Onshore Synchronous Generating Unit(s)**:

(i) have a **Connection Entry Capacity** which has been increased above **Rated MW** (or the **Connection Entry Capacity** of the **CCGT module** has increased above the sum of the **Rated MW** of the **Generating Units** compromising the **CCGT module**), and such increase takes effect after 1st May 2009, the minimum lagging **Reactive Power** capability at the terminals of the **Onshore Synchronous Generating Unit(s)** must be 0.9 **Power Factor** at all **Active Power** output levels in excess of **Rated MW**. Further, the **User** shall comply with the provisions of and any instructions given pursuant to BC1.8 and the relevant **Bilateral Agreement**; or

(ii) 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 a **Completion Date** before 1st May 2009, alternative provisions relating to **Reactive Power** capability may be specified in the **Bilateral Agreement** and where this is the case such provisions must be complied with.

The short circuit ratio of **Onshore Synchronous Generating Units** with an **Apparent Power** rating of less than 1600MVA shall be not less than 0.5. The short circuit ratio of **Onshore Synchronous Generating Units** with a rated **Apparent Power** of 1600MVA or above shall be not less than 0.4.

(b) Subject to paragraph (c) below, all **Onshore Non-Synchronous Generating Units**, **Onshore DC Converters** and **Onshore Power Park Modules** must be capable of maintaining zero transfer of **Reactive Power** at the **Onshore Grid Entry Point** (or **User System Entry Point** if **Embedded**) at all **Active Power** output levels under steady state voltage conditions. For **Onshore Non-Synchronous Generating Units** and **Onshore Power Park Modules** the steady state tolerance on **Reactive Power** transfer to and from the **National Electricity Transmission System** expressed in MVAr shall be no greater than 5% of the **Rated MW**. For **Onshore DC Converters** the steady state tolerance on **Reactive Power** transfer to and from the **National Electricity Transmission System** shall be specified in the **Bilateral Agreement**.
Subject to the provisions of CC.6.3.2(d) below, all **Onshore Non-Synchronous Generating Units, Onshore DC Converters** (excluding current source technology) and **Onshore Power Park Modules** (excluding those connected to the **Total System** by a current source **Onshore DC Converter**) and **OTSDUW Plant and Apparatus** at the **Interface Point** with a **Completion Date** on or after 1 January 2006 must be capable of supplying **Rated MW output** or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus** at any point between the limits **0.95 Power Factor** lagging and **0.95 Power Factor** leading at the **Onshore Grid Entry Point** in England and Wales or **Interface Point** in the case of **OTSDUW Plant and Apparatus** or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for **GB Generators** directly connected to the **Onshore Transmission System** in Scotland (or **User System Entry Point** if **Embedded**). With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus** at Lagging **Power Factor** will apply at all **Active Power** output levels above **20% of the Rated MW** or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus** output as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits defined at **Rated MW** at Leading **Power Factor** will apply at all **Active Power** output levels above **50% of the Rated MW output or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus** as defined in Figure 1. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below **50% Active Power** output as shown in Figure 1 unless the requirement to maintain the **Reactive Power** limits defined at **Rated MW or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus** at Leading **Power Factor** down to **20% Active Power** output is specified in the **Bilateral Agreement**. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service.

![Figure 1](image-url)

**Point A** is equivalent (in MVAr) to **0.95 leading Power Factor** at **Rated MW output or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**

**Point B** is equivalent (in MVAr) to **0.95 lagging Power Factor** at **Rated MW output or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**

**Point C** is equivalent (in MVAr) to **-5% of Rated MW output or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**

**Point D** is equivalent (in MVAr) to **+5% of Rated MW output or Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**
Point E is equivalent -12% of Rated MW output or Interface Point Capacity in the case of OTSDUW Plant and Apparatus.

(d) All Onshore Non-Synchronous Generating Units and Onshore Power Park Modules in Scotland with a Completion Date after 1 April 2005 and before 1 January 2006 must be capable of supplying Rated MW at the range of power factors either:

(i) from 0.95 lead to 0.95 lag as illustrated in Figure 1 at the User System Entry Point for Embedded GB Generators or at the HV side of the 33/132kV or 33/275kV or 33/400kV transformer for GB Generators directly connected to the Onshore Transmission System. With all Plant in service, the Reactive Power limits defined at Rated MW will apply at all Active Power output levels above 20% of the Rated MW output as defined in Figure 1. These Reactive Power limits will be reduced pro rata to the amount of Plant in service, or

(ii) from 0.95 lead to 0.90 lag at the Onshore Non-Synchronous Generating Unit (including Power Park Unit) terminals. For the avoidance of doubt GB Generators complying with this option (ii) are not required to comply with CC.6.3.2(b).

(e) The short circuit ratio of Offshore Synchronous Generating Units at a Large Power Station shall be not less than 0.5. At a Large Power Station all Offshore Synchronous Generating Units, Offshore Non-Synchronous Generating Units, Offshore DC Converters and Offshore Power Park Modules must be capable of maintaining:

(i) zero transfer of Reactive Power at the Offshore Grid Entry Point for all GB Generators with an Offshore Grid Entry Point at the LV Side of the Offshore Platform at all Active Power output levels under steady state voltage conditions. The steady state tolerance on Reactive Power transfer to and from an Offshore Transmission System expressed in MVAr shall be no greater than 5% of the Rated MW, or

(ii) a transfer of Reactive Power at the Offshore Grid Entry Point at a value specified in the Bilateral Agreement that will be equivalent to zero at the LV Side of the Offshore Platform. In addition, the steady state tolerance on Reactive Power transfer to and from an Offshore Transmission System expressed in MVAr at the LV Side of the Offshore Platform shall be no greater than 5% of the Rated MW, or

(iii) the Reactive Power capability (within an associated steady state tolerance) specified in the Bilateral Agreement if any alternative has been agreed with the GB Generator, Offshore Transmission Licensee and The Company.

(f) In addition, a Genset shall meet the operational requirements as specified in BC2.A.2.6. Each Generating Unit, DC Converter (including an OTSDUW DC Converter), Power Park Module and/or CCGT Module must be capable of:

(a) continuously maintaining constant Active Power output for System Frequency changes within the range 50.5 to 49.5 Hz; and
(b) (subject to the provisions of CC.6.1.3) maintaining its Active Power output at a level not lower than the figure determined by the linear relationship shown in Figure 2 for System Frequency changes within the range 49.5 to 47 Hz, such that if the System Frequency drops to 47 Hz the Active Power output does not decrease by more than 5%. In the case of a CCGT Module, the above requirement shall be retained down to the Low Frequency Relay trip setting of 48.8 Hz, which reflects the first stage of the automatic low Frequency Demand Disconnection scheme notified to Network Operators under OC6.6.2. For System Frequency below that setting, the existing requirement shall be retained for a minimum period of 5 minutes while System Frequency remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minute period, if System Frequency remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the Gas Turbine tripping. The need for special measure(s) is linked to the inherent Gas Turbine Active Power output reduction caused by reduced shaft speed due to falling System Frequency.

![Figure 2](image)

(c) For the avoidance of doubt, in the case of a Generating Unit or Power Park Module (or OTSDUW DC Converters at the Interface Point) using an Intermittent Power Source where the mechanical power input will not be constant over time, the requirement is that the Active Power output shall be independent of System Frequency under (a) above and should not drop with System Frequency by greater than the amount specified in (b) above.

(d) A DC Converter Station must be capable of maintaining its Active Power input (i.e. when operating in a mode analogous to Demand) from the National Electricity Transmission System (or User System in the case of an Embedded DC Converter Station) at a level not greater than the figure determined by the linear relationship shown in Figure 3 for System Frequency changes within the range 49.5 to 47 Hz, such that if the System Frequency drops to 47.8 Hz the Active Power input decreases by more than 60%.
(e) At a Large Power Station, in the case of an Offshore Generating Unit, Offshore Power Park Module, Offshore DC Converter and OTSDUW DC Converter, the GB Generator shall comply with the requirements of CC.6.3.3. GB Generators should be aware that Section K of the STC places requirements on Offshore Transmission Licensees which utilise a Transmission DC Converter as part of their Offshore Transmission System to make appropriate provisions to enable GB Generators to fulfil their obligations.

(f) In the case of an OTSDUW DC Converter the OTSDUW Plant and Apparatus shall provide a continuous signal indicating the real time frequency measured at the Interface Point to the Offshore Grid Entry Point.

CC.6.3.4

At the Grid Entry Point, the Active Power output under steady state conditions of any Generating Unit, DC Converter or Power Park Module directly connected to the National Electricity Transmission System or in the case of OTSDUW, the Active Power transfer at the Interface Point, under steady state conditions of any OTSDUW Plant and Apparatus should not be affected by voltage changes in the normal operating range specified in paragraph CC.6.1.4 by more than the change in Active Power losses at reduced or increased voltage. In addition:

(a) For any Onshore Generating Unit, Onshore DC Converter and Onshore Power Park Module or OTSDUW Plant and Apparatus, the Reactive Power output under steady state conditions should be fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages, except for an Onshore Power Park Module or Onshore Non-Synchronous Generating Unit if Embedded at 33kV and below (or directly connected to the Onshore Transmission System at 33kV and below) where the requirement shown in Figure 4 applies.

(b) At a Large Power Station, in the case of an Offshore Generating Unit, Offshore DC Converter and Offshore Power Park Module where an alternative reactive capability has been agreed with the GB Generator, as specified in CC.6.3.2(e) (iii), the voltage / Reactive Power requirement shall be specified in the Bilateral Agreement. The Reactive Power output under steady state conditions shall be fully available within the voltage range ±5% at 400kV, 275kV and 132kV and lower voltages.
Voltage at an **Onshore Grid Entry Point** or **User System Entry Point** if Embedded (% of Nominal) at 33 kV and below

**Figure 4**

**CC.6.3.5**  
It is an essential requirement that the **National Electricity Transmission System** must incorporate a **Black Start Capability**. This will be achieved by agreeing a **Black Start Capability** with a number of strategically located **Black Start Service Providers**. For each **Black Start Service Provider** the Company will state in the **Bilateral Agreement** whether or not a **Black Start Capability** is required. For the avoidance of doubt, a GBGF-I designed with a **Black Start Capability** will also be required to have a **Grid Forming Capability** in accordance with the requirements of ECC.6.3.19.

**Control Arrangements**

**CC.6.3.6** *(a)* Each:

(i) **Offshore Generating Unit** in a **Large Power Station** or **Onshore Generating Unit**; or,

(ii) **Onshore DC Converter** with a **Completion Date** on or after 1 April 2005 or **Offshore DC Converter** at a **Large Power Station**; or,

(iii) **Onshore Power Park Module** in England and Wales with a **Completion Date** on or after 1 January 2006; or,

(iv) **Onshore Power Park Module** in operation in Scotland on or after 1 January 2006 (with a **Completion Date** after 1 July 2004 and in a **Power Station** with a **Registered Capacity** of 50MW or more); or,

(v) **Offshore Power Park Module** in a **Large Power Station** with a **Registered Capacity** of 50MW or more;

must be capable of contributing to **Frequency** control by continuous modulation of **Active Power** supplied to the **National Electricity Transmission System** or the **User System** in which it is **Embedded**. For the avoidance of doubt, each OTSDUW DC Converter shall provide each **GB Code User** in respect of its **Offshore Power Stations** connected to and/or using an **Offshore Transmission System** a continuous signal indicating the real time **Frequency** measured at the **Transmission Interface Point**.

*(b)* Each:

(i) **Onshore Generating Unit**; or,

(ii) **Onshore DC Converter** (with a **Completion Date** on or after 1 April 2005 excluding current source technologies); or
(iii) Onshore Power Park Module in England and Wales with a Completion Date on or after 1 January 2006; or,

(iv) Onshore Power Park Module in Scotland irrespective of Completion Date; or,

(v) Offshore Generating Unit at a Large Power Station, Offshore DC Converter at a Large Power Station or Offshore Power Park Module at a Large Power Station which provides a reactive range beyond the minimum requirements specified in CC.6.3.2(e) (iii); or,

(vi) OTSDUW Plant and Apparatus at a Transmission Interface Point

must be capable of contributing to voltage control by continuous changes to the Reactive Power supplied to the National Electricity Transmission System or the User System in which it is Embedded.

CC.6.3.7

(a) Each Generating Unit, DC Converter or Power Park Module (excluding Onshore Power Park Modules in Scotland with a Completion Date before 1 July 2004 or Onshore Power Park Modules in a Power Station in Scotland with a Registered Capacity less than 50MW or Offshore Power Park Modules in a Large Power Station located Offshore with a Registered Capacity less than 50MW) must be fitted with a fast acting proportional Frequency control device (or turbine speed governor) and unit load controller or equivalent control device to provide Frequency response under normal operational conditions in accordance with Balancing Code 3 (BC3). In the case of a Power Park Module the Frequency or speed control device(s) may be on the Power Park Module or on each individual Power Park Unit or be a combination of both. The Frequency control device(s) (or speed governor(s)) must be designed and operated to the appropriate:

(i) European Specification; or

(ii) in the absence of a relevant European Specification, such other standard which is in common use within the European Community (which may include a manufacturer specification);

as at the time when the installation of which it forms part was designed or (in the case of modification or alteration to the Frequency control device (or turbine speed governor)) when the modification or alteration was designed.

The European Specification or other standard utilised in accordance with sub-paragraph CC.6.3.7 (a) (ii) will be notified to The Company by the GB Generator or DC Converter Station owner or, in the case of an Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded DC Converter Station not subject to a Bilateral Agreement, the relevant Network Operator:

(i) as part of the application for a Bilateral Agreement; or

(ii) as part of the application for a varied Bilateral Agreement; or

(iii) in the case of an Embedded Development, within 28 days of entry into the Embedded Development Agreement (or such later time as agreed with The Company); or

(iv) as soon as possible prior to any modification or alteration to the Frequency control device (or governor); and

(b) The Frequency control device (or speed governor) in co-ordination with other control devices must control the Generating Unit, DC Converter or Power Park Module Active Power Output with stability over the entire operating range of the Generating Unit, DC Converter or Power Park Module; and

(c) The Frequency control device (or speed governor) must meet the following minimum requirements:

(i) Where a Generating Unit, DC Converter or Power Park Module becomes isolated
from the rest of the **Total System** but is still supplying **Customers**, the **Frequency** control device (or speed governor) must also be able to control **System Frequency** below 52Hz unless this causes the **Generating Unit, DC Converter** or **Power Park Module** to operate below its **Designed Minimum Operating Level** when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt, the **Generating Unit, DC Converter** or **Power Park Module** is only required to operate within the **System Frequency** range 47 - 52 Hz as defined in CC.6.1.3;

(iii) the **Frequency** control device (or speed governor) must be capable of being set so that it operates with an overall speed **Droop** of between 3% and 5%. For the avoidance of doubt, in the case of a **Power Park Module** the speed **Droop** should be equivalent of a fixed setting between 3% and 5% applied to each **Power Park Unit** in service;

(iii) in the case of all **Generating Units, DC Converter** or **Power Park Module** other than the **Steam Unit** within a **CCGT Module** the **Frequency** control device (or speed governor) deadband should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the speed **Governor Deadband** should be set to an appropriate value consistent with the requirements of CC.6.3.7(c)(i) and the requirements of BC3.7.2 for the provision of **Limited High Frequency Response**;

For the avoidance of doubt, the minimum requirements in (ii) and (iii) for the provision of **System Ancillary Services** do not restrict the negotiation of **Commercial Ancillary Services** between **The Company** and the **GB Code User** using other parameters; and

(d) A facility to modify, so as to fulfil the requirements of the **Balancing Codes**, the **Target Frequency** setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 ±0.1 Hz should be provided in the unit load controller or equivalent device.

(e) (i) Each **Onshore Generating Unit** and/or **CCGT Module** which has a **Completion Date** after 1 January 2001 in England and Wales, and after 1 April 2005 in Scotland, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(ii) Each **DC Converter** at a **DC Converter Station** which has a **Completion Date** on or after 1 April 2005 and each **Offshore DC Converter** at a **Large Power Station** must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(iii) Each **Offshore Power Park Module** in operation in England and Wales with a **Completion Date** on or after 1 January 2006 must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(iv) Each **Offshore Power Park Module** in operation on or after 1 January 2006 in Scotland (with a **Completion Date** on or after 1 April 2005 and a **Registered Capacity** of 50MW or more) must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(v) Each **Offshore Generating Unit** in a **Large Power Station** must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(vi) Each **Offshore Power Park Module** in a **Large Power Station** with a **Registered Capacity** of 50 MW or greater, must be capable of meeting the minimum **Frequency** response requirement profile subject to and in accordance with the provisions of Appendix 3.

(vii) Subject to the requirements of CC.6.3.7(e), **Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station** and **Offshore DC Converters in a Large Power Station** shall comply with the requirements of CC.6.3.7. **GB Generators** should be aware that Section K of the
STC places requirements on Offshore Transmission Licensees which utilise a Transmission DC Converter as part of their Offshore Transmission System to make appropriate provisions to enable GB Generators to fulfil their obligations.

(viii) Each OTSDUW DC Converter must be capable of providing a continuous signal indicating the real time frequency measured at the Interface Point to the Offshore Grid Entry Point.

(f) For the avoidance of doubt, the requirements of Appendix 3 do not apply to:

(i) Generating Units and/or CCGT Modules which have a Completion Date before 1 January 2001 in England and Wales, and before 1 April 2005 in Scotland, for whom the remaining requirements of this clause CC.6.3.7 shall continue to apply unchanged; or

(ii) DC Converters at a DC Converter Station which have a Completion Date before 1 April 2005; or

(iii) Onshore Power Park Modules in England and Wales with a Completion Date before 1 January 2006 for whom only the requirements of Limited Frequency Sensitive Mode (BC3.5.2) operation shall apply; or

(iv) Onshore Power Park Modules in operation in Scotland before 1 January 2006 for whom only the requirements of Limited Frequency Sensitive Mode (BC3.5.2) operation shall apply; or

(v) Onshore Power Park Modules in operation after 1 January 2006 in Scotland which have a Completion Date before 1 April 2005 for whom the remaining requirements of this clause CC.6.3.7 shall continue to apply unchanged; or

(vi) Offshore Power Park Modules which are in a Large Power Station with a Registered Capacity less than 50MW for whom only the requirements of Limited Frequency Sensitive Mode (BC3.5.2) operation shall apply; or

Excitation and Voltage Control Performance Requirements

CC.6.3.8 (a) Excitation and voltage control performance requirements applicable to Onshore Generating Units, Onshore Power Park Modules, Onshore DC Converters and OTSDUW Plant and Apparatus.

(i) A continuously-acting automatic excitation control system is required to provide constant terminal voltage control of the Onshore Synchronous Generating Unit without instability over the entire operating range of the Onshore Generating Unit.

(ii) In respect of Onshore Synchronous Generating Units with a Completion Date before 1 January 2009, the requirements for excitation control facilities, including Power System Stabilisers, where in The Company’s view these are necessary for system reasons, will be specified in the Bilateral Agreement. If any Modification to the excitation control facilities of such Onshore Synchronous Generating Units is made on or after 1 January 2009 the requirements that shall apply may be specified in the Bilateral Agreement as varied. To the extent that the Bilateral Agreement does not specify, the requirements given or referred to in CC.A.6 shall apply. The performance requirements for a continuously acting automatic excitation control system that shall be complied with by the GB Code User in respect of such Onshore Synchronous Generating Units with a Completion Date on or after 1 January 2009 are given or referred to in CC.A.6. Reference is made to on-load commissioning witnessed by The Company in BC2.11.2.

(iii) In the case of an Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus at the Interface Point a continuously-acting automatic control system is required to provide control of the voltage (or zero transfer of Reactive Power as applicable to CC.6.3.2) at the Offshore Grid Entry Point or User System Entry Point or in the case of OTSDUW Plant and Apparatus at the Interface Point without instability over the entire operating range of the Onshore Non-Synchronous Generating
Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus. Any Plant or Apparatus used in the provisions of such voltage control within an Onshore Power Park Module may be located at the Power Park Unit terminals, an appropriate intermediate busbar or the Connection Point. OTSDUW Plant and Apparatus used in the provision of such voltage control may be located at the Offshore Grid Entry Point, an appropriate intermediate busbar or at the Interface Point. In the case of an Onshore Power Park Module in Scotland with a Completion Date before 1 January 2009, voltage control may be at the Power Park Unit terminals, an appropriate intermediate busbar or the Connection Point as specified in the Bilateral Agreement. When operating below 20% Rated MW the automatic control system may continue to provide voltage control utilising any available reactive capability. If voltage control is not being provided, the automatic control system shall be designed to ensure a smooth transition between the shaded area bound by CD and the non-shaded area bound by AB in Figure 1 of CC.6.3.2 (c).

(iv) The performance requirements for a continuously acting automatic voltage control system in respect of Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters with a Completion Date before 1 January 2009 will be specified in the Bilateral Agreement. If any Modification to the continuously acting automatic voltage control system of such Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters is made on or after 1 January 2009 the requirements that shall apply may be specified in the Bilateral Agreement as varied. To the extent that the Bilateral Agreement does not specify, the requirements given or referred to in CC.A.7 shall apply. The performance requirements for a continuously acting automatic voltage control system that shall be complied with by the GB Code User in respect of Onshore Power Park Modules, Onshore Non-Synchronous Generating Units and Onshore DC Converters or OTSDUW Plant and Apparatus at the Interface Point with a Completion Date on or after 1 January 2009 are given or referred to in CC.A.7.

(v) Unless otherwise required for testing in accordance with OC5.A.2, the automatic excitation control system of an Onshore Synchronous Generating Unit shall always be operated such that it controls the Onshore Synchronous Generating Unit terminal voltage to a value that is

- equal to its rated value; or
- only where provisions have been made in the Bilateral Agreement, greater than its rated value.

(vi) In particular, other control facilities, including constant Reactive Power output control modes and constant Power Factor control modes (but excluding VAr limiters) are not required. However, if present in the excitation or voltage control system they will be disabled unless the Bilateral Agreement records otherwise. Operation of such control facilities will be in accordance with the provisions contained in BC2.

(b) Excitation and voltage control performance requirements applicable to Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station.

A continuously acting automatic control system is required to provide either:

(i) control of Reactive Power (as specified in CC.6.3.2(e) (i) (ii)) at the Offshore Grid Entry Point without instability over the entire operating range of the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module. The performance requirements for this automatic control system will be specified in the Bilateral Agreement or;

(ii) where an alternative reactive capability has been specified in the Bilateral Agreement, in accordance with CC.6.3.2 (e) (iii), the Offshore Generating Unit,
Offshore Power Park Module or Offshore DC Converter will be required to control voltage and/or Reactive Power without instability over the entire operating range of the Offshore Generating Unit, Offshore Power Park Module or Offshore DC Converter. The performance requirements of the control system will be specified in the Bilateral Agreement.

In addition to CC.6.3.8(b) (i) and (ii) the requirements for excitation control facilities, including Power System Stabilisers, where in The Company’s view these are necessary for system reasons, will be specified in the Bilateral Agreement. Reference is made to on-load commissioning witnessed by The Company in BC2.11.2.

Steady state Load Inaccuracies

CC.6.3.9 The standard deviation of Load error at steady state Load over a 30 minute period must not exceed 2.5 per cent of a Genset’s Registered Capacity. Where a Genset is instructed to Frequency sensitive operation, allowance will be made in determining whether there has been an error according to the governor droop characteristic registered under the PC.

For the avoidance of doubt in the case of a Power Park Module allowance will be made for the full variation of mechanical power output.

Negative Phase Sequence Loadings

CC.6.3.10 In addition to meeting the conditions specified in CC.6.1.5(b), each Synchronous Generating Unit will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by System Back-Up Protection on the National Electricity Transmission System or User System located Onshore in which it is Embedded.

Neutral Earthing

CC.6.3.11 At nominal System voltages of 132kV and above the higher voltage windings of a transformer of a Generating Unit, DC Converter, Power Park Module or transformer resulting from OTSDUW must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph CC.6.2.1.1 (b) will be met on the National Electricity Transmission System at nominal System voltages of 132kV and above.

Frequency Sensitive Relays

CC.6.3.12 As stated in CC.6.1.3, the System Frequency could rise to 52Hz or fall to 47Hz. Each Generating Unit, DC Converter, OTSDUW Plant and Apparatus, Power Park Module or any constituent element must continue to operate within this Frequency range for at least the periods of time given in CC.6.1.3 unless The Company has agreed to any Frequency-level relays and/or rate-of-change-of-Frequency relays which will trip such Generating Unit, DC Converter, OTSDUW Plant and Apparatus, Power Park Module and any constituent element within this Frequency range, under the Bilateral Agreement.

CC.6.3.13 GB Generators (including in respect of OTSDUW Plant and Apparatus) and DC Converter Station owners will be responsible for protecting all their Generating Units (and OTSDUW Plant and Apparatus), DC Converters or Power Park Modules against damage should Frequency excursions outside the range 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the GB Generator or DC Converter Station owner to decide whether to disconnect their Apparatus for reasons of safety of Apparatus, Plant and/or personnel.

CC.6.3.14 It may be agreed in the Bilateral Agreement that a Genset shall have a Fast-Start Capability. Such Gensets may be used for Operating Reserve and their Start-Up may be initiated by Frequency-level relays with settings in the range 49Hz to 50Hz as specified pursuant to OC2.
Fault Ride Through

This section sets out the fault ride through requirements on Generating Units, Power Park Modules, DC Converters and OTSDUW Plant and Apparatus. Onshore Generating Units, Onshore Power Park Modules, Onshore DC Converters (including Embedded Medium Power Stations and Embedded DC Converter Stations not subject to a Bilateral Agreement and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)) and OTSDUW Plant and Apparatus are required to operate through System faults and disturbances as defined in CC.6.3.15.1 (a), CC.6.3.15.1 (b) and CC.6.3.15.3. Offshore GB Generators in respect of Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and DC Converter Station owners in respect of Offshore DC Converters at a Large Power Station shall have the option of meeting either:

(i) CC.6.3.15.1 (a), CC.6.3.15.1 (b) and CC.6.3.15.3, or:

(ii) CC.6.3.15.2 (a), CC.6.3.15.2 (b) and CC.6.3.15.3

Offshore GB Generators and Offshore DC Converter owners, should notify The Company which option they wish to select within 28 days (or such longer period as The Company may agree, in any event this being no later than 3 months before the Completion Date of the offer for a final CUSC Contract which would be made following the appointment of the Offshore Transmission Licensee).

Fault Ride through applicable to Generating Units, Power Park Modules and DC Converters and OTSDUW Plant and Apparatus

(a) Short circuit faults on the Onshore Transmission System (which may include an Interface Point) at Supergrid Voltage up to 140ms in duration.

(i) Each Generating Unit, DC Converter, or Power Park Module and any constituent Power Park Unit thereof and OTSDUW Plant and Apparatus shall remain transiently stable and connected to the System without tripping of any Generating Unit, DC Converter or Power Park Module and / or any constituent Power Park Unit, OTSDUW Plant and Apparatus, and for Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment, for a close-up solid three-phase short circuit fault or any unbalanced short circuit fault on the Onshore Transmission System (including in respect of OTSDUW Plant and Apparatus, the Interface Point) operating at Supergrid Voltages for a total fault clearance time of up to 140 ms. A solid three-phase or unbalanced earthed fault results in zero voltage on the faulted phase(s) at the point of fault. The duration of zero voltage is dependent on local Protection and circuit breaker operating times. This duration and the fault clearance times will be specified in the Bilateral Agreement. Following fault clearance, recovery of the Supergrid Voltage on the Onshore Transmission System to 90% may take longer than 140ms as illustrated in Appendix 4A Figures CC.A.4A.1 (a) and (b). It should be noted that in the case of an Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a fault on the Onshore Transmission System. The fault will affect the level of Active Power that can be transferred to the Onshore Transmission System and therefore subject the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.

(ii) Each Generating Unit, Power Park Module and OTSDUW Plant and Apparatus, shall be designed such that upon both clearance of the fault on the Onshore Transmission System as detailed in CC.6.3.15.1 (a) (i) and within 0.5 seconds of the restoration of the voltage at the Offshore Grid Entry Point (for Offshore Generating Units or Offshore Power Park Modules) or Interface Point (for Offshore Generating Units, Offshore Power Park Modules or OTSDUW Plant...
and Apparatus) to the minimum levels specified in CC.6.1.4 (or within 0.5 seconds of restoration of the voltage at the User System Entry Point to 90% of nominal or greater if Embedded), Active Power output or in the case of OTSDUW Plant and Apparatus, Active Power transfer capability, shall be restored to at least 90% of the level available immediately before the fault. Once the Active Power output, or in the case of OTSDUW Plant and Apparatus, Active Power transfer capability, has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped

During the period of the fault as detailed in CC.6.3.15.1 (a) (i) for which the voltage at the Grid Entry Point (or Interface Point in the case of OTSDUW Plant and Apparatus) is outside the limits specified in CC.6.1.4, each Generating Unit or Power Park Module or OTSDUW Plant and Apparatus shall generate maximum reactive current without exceeding the transient rating limit of the Generating Unit, OTSDUW Plant and Apparatus or Power Park Module and / or any constituent Power Park Unit or reactive compensation equipment. For Plant and Apparatus installed on or after 1 December 2017, switched reactive compensation equipment (such as mechanically switched capacitors and reactors) shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery.

(iii) Each DC Converter shall be designed to meet the Active Power recovery characteristics (and OTSDUW DC Converter shall be designed to meet the Active Power transfer capability at the Interface Point) as specified in the Bilateral Agreement upon clearance of the fault on the Onshore Transmission System as detailed in CC.6.3.15.1 (a) (i).

(b) Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration

(1b) Requirements applicable to Synchronous Generating Units subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.1 (a) each Synchronous Generating Unit, each with a Completion Date on or after 1 April 2005 shall:

(i) remain transiently stable and connected to the System without tripping of any Synchronous Generating Unit for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure 5a. Appendix 4A and Figures CC.A.4A.3.2 (a), (b) and (c) provide an explanation and illustrations of Figure 5a; and,
(ii) provide Active Power output at the Grid Entry Point, during Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5a, at least in proportion to the retained balanced voltage at the Onshore Grid Entry Point (for Onshore Synchronous Generating Units) or Interface Point (for Offshore Synchronous Generating Units) (or the retained balanced voltage at the User System Entry Point if Embedded) and shall generate maximum reactive current (where the voltage at the Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Synchronous Generating Unit and,

(iii) restore Active Power output following Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5a, within 1 second of restoration of the voltage to 1.0p.u of the nominal voltage at the:

- Onshore Grid Entry Point for directly connected Onshore Synchronous Generating Units or,
- Interface Point for Offshore Synchronous Generating Units or,
- User System Entry Point for Embedded Onshore Synchronous Generating Units or,
- User System Entry Point for Embedded Medium Power Stations not subject to a Bilateral Agreement which comprise Synchronous Generating Units and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)

...to at least 90% of the level available immediately before the occurrence of the dip. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

For the avoidance of doubt a balanced Onshore Transmission System Supergrid Voltage meets the requirements of CC.6.1.5 (b) and CC.6.1.6.

(2b) Requirements applicable to OTSDUW Plant and Apparatus and Power Park Modules subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration
In addition to the requirements of CC.6.3.15.1 (a) each OTSDUW Plant and Apparatus or each Power Park Module and / or any constituent Power Park Unit, each with a Completion Date on or after the 1 April 2005 shall:

(i) remain transiently stable and connected to the System without tripping of any OTSDUW Plant and Apparatus, or Power Park Module and / or any constituent Power Park Unit, for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure 5b. Appendix 4A and Figures CC.A.4A.3.4 (a), (b) and (c) provide an explanation and illustrations of Figure 5b; and,

(ii) provide Active Power output at the Grid Entry Point or in the case of an OTSDUW, Active Power transfer capability at the Transmission Interface Point, during Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5b, at least in proportion to the retained balanced voltage at the Onshore Grid Entry Point (for Onshore Power Park Modules) or Interface Point (for OTSDUW Plant and Apparatus and Offshore Power Park Modules) (or the retained balanced voltage at the User System Entry Point if Embedded) except in the case of a Non-Synchronous Generating Unit or OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source or in the case of OTSDUW Active Power transfer capability in the time range in Figure 5b that restricts the Active Power output or in the case of an OTSDUW Active Power transfer capability below this level and shall generate maximum reactive current (where the voltage at the Grid Entry Point, or in the case of an OTSDUW Plant and Apparatus, the Interface Point voltage, is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the OTSDUW Plant and Apparatus or Power Park Module and any constituent Power Park Unit; and,

(iii) restore Active Power output (or, in the case of OTSDUW, Active Power transfer capability), following Supergrid Voltage dips on the Onshore Transmission System as described in Figure 5b, within 1 second of restoration of the voltage at the:

Onshore Grid Entry Point for directly connected Onshore Power Park Modules or,

Interface Point for OTSDUW Plant and Apparatus and Offshore Power Park Modules.
Modules or,
User System Entry Point for Embedded Onshore Power Park Modules or,
User System Entry Point for Embedded Medium Power Stations which comprise Power Park Modules not subject to a Bilateral Agreement and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)

to the minimum levels specified in CC.6.1.4 to at least 90% of the level available immediately before the occurrence of the dip except in the case of a Non-Synchronous Generating Unit, OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 5b that restricts the Active Power output or, in the case of OTSDUW, Active Power transfer capability below this level. Once the Active Power output or, in the case of OTSDUW, Active Power transfer capability has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

For the avoidance of doubt a balanced Onshore Transmission System Supergrid Voltage meets the requirements of CC.6.1.5 (b) and CC.6.1.6.

CC.6.3.15.2 Fault Ride Through applicable to Offshore Generating Units at a Large Power Station, Offshore Power Park Modules at a Large Power Station and Offshore DC Converters at a Large Power Station who choose to meet the fault ride through requirements at the LV side of the Offshore Platform

(a) Requirements on Offshore Generating Units, Offshore Power Park Modules and Offshore DC Converters to withstand voltage dips on the LV Side of the Offshore Platform for up to 140ms in duration as a result of faults and / or voltage dips on the Onshore Transmission System operating at Supergrid Voltage.

(i) Each Offshore Generating Unit, Offshore DC Converter, or Offshore Power Park Module and any constituent Power Park Unit thereof shall remain transiently stable and connected to the System without tripping of any Offshore Generating Unit, or Offshore DC Converter or Offshore Power Park Module and / or any constituent Power Park Unit or, in the case of Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment, for any balanced or unbalanced voltage dips on the LV Side of the Offshore Platform whose profile is anywhere on or above the heavy black line shown in Figure 6. For the avoidance of doubt, the profile beyond 140ms in Figure 6 shows the minimum recovery in voltage that will be seen by the Generator’s Plant and Apparatus following clearance of the fault at 140ms. Appendix 4B and Figures CC.A.4B.2 (a) and (b) provide further illustration of the voltage recovery profile that may be seen. It should be noted that in the case of an Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a fault on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Offshore Transmission System and therefore subject the Offshore Generating Unit, Offshore DC Converter or Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.
Figure 6

V/V_N is the ratio of the actual voltage on one or more phases at the LV Side of the Offshore Platform to the nominal voltage of the LV Side of the Offshore Platform.

(ii) Each Offshore Generating Unit, or Offshore Power Park Module and any constituent Power Park Unit thereof shall provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 6, at least in proportion to the retained voltage at the LV Side of the Offshore Platform except in the case of an Offshore Non-Synchronous Generating Unit or Offshore Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 6 that restricts the Active Power output below this level and shall generate maximum reactive current without exceeding the transient rating limits of the Offshore Generating Unit or Offshore Power Park Module and any constituent Power Park Unit or, in the case of Plant and Apparatus installed on or after 1 December 2017, reactive compensation equipment. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant

- the oscillations are adequately damped

and;

(iii) Each Offshore DC Converter shall be designed to meet the Active Power recovery characteristics as specified in the Bilateral Agreement upon restoration of the voltage at the LV Side of the Offshore Platform.

(b) Requirements of Offshore Generating Units, Offshore Power Park Modules, to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.

(1b) Requirements applicable to Offshore Synchronous Generating Units to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.2. (a) each Offshore Synchronous Generating Unit shall:

(i) remain transiently stable and connected to the System without tripping of any Offshore Synchronous Generating Unit for any balanced voltage dips on the LV
side of the Offshore Platform and associated durations anywhere on or above the heavy black line shown in Figure 7a. Appendix 4B and Figures CC.A.4B.3.2 (a), (b) and (c) provide an explanation and illustrations of Figure 7a. It should be noted that in the case of an Offshore Synchronous Generating Unit which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a voltage dip on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Onshore Transmission System and therefore subject the Offshore Generating Unit, to a load rejection.

(ii) provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 7a, at least in proportion to the retained balanced or unbalanced voltage at the LV Side of the Offshore Platform and shall generate maximum reactive current (where the voltage at the Offshore Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Offshore Synchronous Generating Unit and,

(iii) within 1 second of restoration of the voltage to 1.0p.u of the nominal voltage at the LV Side of the Offshore Platform, restore Active Power to at least 90% of the Offshore Synchronous Generating Unit’s immediate pre-disturbed value, unless there has been a reduction in the Intermittent Power Source in the time range in Figure 7a that restricts the Active Power output below this level. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped

(2b) Requirements applicable to Offshore Power Park Modules to withstand voltage dips on the LV Side of the Offshore Platform greater than 140ms in duration.

In addition to the requirements of CC.6.3.15.2. (a) each Offshore Power Park Module and / or any constituent Power Park Unit, shall:
(i) remain transiently stable and connected to the System without tripping of any Offshore Power Park Module and/or any constituent Power Park Unit, for any balanced voltage dips on the LV side of the Offshore Platform and associated durations anywhere on or above the heavy black line shown in Figure 7b. Appendix 4B and Figures CC.A.4B.5. (a), (b) and (c) provide an explanation and illustrations of Figure 7b. It should be noted that in the case of an Offshore Power Park Module (including any Offshore Power Park Unit thereof) which is connected to an Offshore Transmission System which includes a Transmission DC Converter as part of that Offshore Transmission System, the Offshore Grid Entry Point voltage may not indicate the presence of a voltage dip on the Onshore Transmission System. The voltage dip will affect the level of Active Power that can be transferred to the Onshore Transmission System and therefore subject the Offshore Power Park Module (including any Offshore Power Park Unit thereof) to a load rejection.

(ii) provide Active Power output, during voltage dips on the LV Side of the Offshore Platform as described in Figure 7b, at least in proportion to the retained balanced or unbalanced voltage at the LV Side of the Offshore Platform except in the case of an Offshore Non-Synchronous Generating Unit or Offshore Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure 7b that restricts the Active Power output below this level and shall generate maximum reactive current (where the voltage at the Offshore Grid Entry Point is outside the limits specified in CC.6.1.4) without exceeding the transient rating limits of the Offshore Power Park Module and any constituent Power Park Unit or reactive compensation equipment. For Plant and Apparatus installed on or after 1 December 2017, switched reactive compensation equipment (such as mechanically switched capacitors and reactors) shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery; and,

(iii) within 1 second of the restoration of the voltage at the LV Side of the Offshore Platform (to the minimum levels specified in CC.6.1.4) restore Active Power to at least 90% of the Offshore Power Park Module’s immediate pre-disturbed value, unless there has been a reduction in the Intermittent Power Source in the time range in Figure 7b that restricts the Active Power output below this level. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant.
- the oscillations are adequately damped

CC.6.3.15.3 **Other Requirements**

(i) In the case of a **Power Park Module** (comprising of wind-turbine generator units), the requirements in CC.6.3.15.1 and CC.6.3.15.2 do not apply when the **Power Park Module** is operating at less than 5% of its **Rated MW** or during very high wind speed conditions when more than 50% of the wind turbine generator units in a **Power Park Module** have been shut down or disconnected under an emergency shutdown sequence to protect GB Code User's Plant and Apparatus.

(ii) In addition to meeting the conditions specified in CC.6.1.5(b) and CC.6.1.6, each **Non-Synchronous Generating Unit, OTSDUW Plant and Apparatus** or **Power Park Module** with a **Completion Date** after 1 April 2005 and any constituent **Power Park Unit** thereof will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by **System Back-Up Protection** on the **Onshore Transmission System** operating at **Supergrid Voltage**.

(iii) In the case of an **Onshore Power Park Module** in Scotland with a **Completion Date** before 1 January 2004 and a **Registered Capacity** less than 30MW, the requirements in CC.6.3.15.1 (a) do not apply. In the case of an **Onshore Power Park Module** in Scotland with a **Completion Date** on or after 1 January 2004 and before 1 July 2005 and a **Registered Capacity** less than 30MW the requirements in CC.6.3.15.1 (a) are relaxed from the minimum **Onshore Transmission System Supergrid Voltage** of zero to a minimum **Onshore Transmission System Supergrid Voltage** of 15% of nominal. In the case of an **Onshore Power Park Module** in Scotland with a **Completion Date** on or after 1 July 2005 and a **Registered Capacity** of 30MW and above the requirements in CC.6.3.15.1 (a) are relaxed from the minimum **Onshore Transmission System Supergrid Voltage** of zero to a minimum **Onshore Transmission System Supergrid Voltage** of 15% of nominal.

(iv) To avoid unwanted island operation, **Non-Synchronous Generating Units** in Scotland (and those directly connected to a **Scottish Offshore Transmission System**), **Power Park Modules** in Scotland (and those directly connected to a **Scottish Offshore Transmission System**), or **OTSDUW Plant and Apparatus** with an **Interface Point** in Scotland shall be tripped for the following conditions:

1. **Frequency** above 52Hz for more than 2 seconds
2. **Frequency** below 47Hz for more than 2 seconds
3. Voltage as measured at the **Onshore Connection Point** or **Onshore User System Entry Point** or **Offshore Grid Entry Point** or **Interface Point** in the case of **OTSDUW Plant and Apparatus** is below 80% for more than 2.5 seconds
4. Voltage as measured at the **Onshore Connection Point** or **Onshore User System Entry Point** or **Offshore Grid Entry Point** or **Interface Point** in the case of **OTSDUW Plant and Apparatus** is above 120% (115% for 275kV) for more than 1 second.

The times in sections (1) and (2) are maximum trip times. Shorter times may be used to protect the **Non-Synchronous Generating Units**, or **OTSDUW Plant and Apparatus** or **Power Park Modules**.

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*Additional Damping Control Facilities for DC Converters*
(a) **DC Converter** owners, or **GB Generators** in respect of **OTSDUW DC Converters** or **Network Operators** in the case of an **Embedded DC Converter Station** not subject to a **Bilateral Agreement** must ensure that any of their **Onshore DC Converters** or **OTSDUW DC Converters** will not cause a sub-synchronous resonance problem on the **Total System**. Each **DC Converter** or **OTSDUW DC Converter** is required to be provided with sub-synchronous resonance damping control facilities.

(b) Where specified in the **Bilateral Agreement**, each **DC Converter** or **OTSDUW DC Converter** is required to be provided with power oscillation damping or any other identified additional control facilities.

**System to Generator Operational Intertripping Scheme**

**CC.6.3.17** The **Company** may require that a **System to Generator Operational Intertripping Scheme** be installed as part of a condition of the connection of the **GB Generator**. Scheme specific details shall be included in the relevant **Bilateral Agreement** and shall, in respect of **Bilateral Agreements** entered into on or after 16th March 2009 include the following information:

1. the relevant category(ies) of the scheme (referred to as Category 1 Intertripping Scheme, Category 2 Intertripping Scheme, Category 3 Intertripping Scheme and Category 4 Intertripping Scheme);

2. the **Generating Unit(s)** or **CCGT Module(s)** or **Power Park Module(s)** to be either permanently armed or that can be instructed to be armed in accordance with BC2.8;

3. the time within which the **Generating Unit(s)** or **CCGT Module(s)** or **Power Park Module(s)** circuit breaker(s) are to be automatically tripped;

4. the location to which the trip signal will be provided by The **Company**. Such location will be provided by The **Company** prior to the commissioning of the **Generating Unit(s)** or **CCGT Module(s)** or **Power Park Module(s)**.

Where applicable, the **Bilateral Agreement** shall include the conditions on the **National Electricity Transmission System** during which The **Company** may instruct the **System to Generator Operational Intertripping Scheme** to be armed and the conditions that would initiate a trip signal.

**CC.6.3.18** The time within which the **Generating Unit(s)** or **CCGT Module** or **Power Park Module** circuit breaker(s) need to be automatically tripped is determined by the specific conditions local to the **GB Generator**. This ‘time to trip’ (defined as time from provision of the trip signal by The **Company** to the specified location, to circuit breaker main contact opening) can typically range from 100ms to 10sec. A longer time to trip may allow the initiation of an automatic reduction in the **Generating Unit(s)** or **CCGT Module(s)** or **Power Park Module(s)** output prior to the automatic tripping of the **Generating Unit(s)** or **CCGT Module(s)** or **Power Park Module(s)** circuit breaker. Where applicable The **Company** may provide separate trip signals to allow for either a longer or shorter ‘time to trip’ to be initiated.

**CC.6.4** General Network Operator And Non-Embedded Customer Requirements

**CC.6.4.1** This part of the **Grid Code** describes the technical and design criteria and performance requirements for **Network Operators** and **Non-Embedded Customers**.
Neutral Earthing

CC.6.4.2 At nominal System voltages of 132kV and above the higher voltage windings of three phase transformers and transformer banks connected to the National Electricity Transmission System must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph CC.6.2.1.1 (b) will be met on the National Electricity Transmission System at nominal System voltages of 132kV and above.

Frequency Sensitive Relays

CC.6.4.3 As explained under OC6, each Network Operator, will make arrangements that will facilitate automatic low Frequency Disconnection of Demand (based on Annual ACS Conditions). CC.A.5.5. of Appendix 5 includes specifications of the local percentage Demand that shall be disconnected at specific frequencies. The manner in which Demand subject to low Frequency disconnection will be split into discrete MW blocks is specified in OC6.6. Technical requirements relating to Low Frequency Relays are also listed in Appendix 5.

Operational Metering

CC.6.4.4 Where The Company can reasonably demonstrate that an Embedded Medium Power Station or Embedded DC Converter Station has a significant effect on the National Electricity Transmission System, it may require the Network Operator within whose System the Embedded Medium Power Station or Embedded DC Converter Station is situated to ensure that the operational metering equipment described in CC.6.5.6 is installed such that The Company can receive the data referred to in CC.6.5.6. In the case of an Embedded Medium Power Station subject to, or proposed to be subject to a Bilateral Agreement, The Company shall notify such Network Operator of the details of such installation in writing within 3 months of being notified of the application to connect under CUSC and in the case of an Embedded Medium Power Station not subject to, or not proposed to be subject to a Bilateral Agreement in writing as a Site Specific Requirement in accordance with the timescales in CUSC 6.5.5. In either case the Network Operator shall ensure that the data referred to in CC.6.5.6 is provided to The Company.

Communications Plant

CC.6.5 Communications Plant

CC.6.5.1 In order to ensure control of the National Electricity Transmission System, telecommunications between GB Code Users and The Company must (including in respect of any OTSDUW Plant and Apparatus at the OTSUA Transfer Time), if required by The Company, be established in accordance with the requirements set down below.

Control Telephony and System Telephony

CC.6.5.2 Control Telephony and System Telephony

CC.6.5.2.1 Control Telephony is the principle method by which a User's Responsible Engineer/Operator and The Company's Control Engineers speak to one another for the purposes of control of the Total System in both normal and emergency operating conditions. Control Telephony provides secure point to point telephony for routine Control Calls, priority Control Calls and emergency Control Calls.

CC.6.5.2.2 System Telephony is an alternate method by which a User's Responsible Engineer/Operator and The Company's Control Engineers speak to one another for the purposes of control of the Total System in both normal operating conditions and where practicable, emergency operating conditions. System Telephony uses an appropriate public communications network to provide telephony for Control Calls, inclusive of emergency Control Calls. For the avoidance of doubt, System Telephony could include but shall not be limited to: an analogue or digital telephone line; a mobile telephone or an internet-based voice communication system, all of which shall be connected to an appropriate public communications network.

CC.6.5.2.3 Calls made and received over Control Telephony and System Telephony may be recorded and subsequently replayed for commercial and operational reasons.

CC.6.5.4 Obligations in respect of Control Telephony and System Telephony
Where The Company requires Control Telephony, Users are required to use the Control Telephony with The Company in respect of all Connection Points with the National Electricity Transmission System and in respect of all Embedded Large Power Stations and Embedded DC Converter Stations. The Company will have Control Telephony installed at the GB Code User’s Control Point where the GB Code User’s telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the Transmission Control Telephony. Details of and relating to the Control Telephony required are contained in the Bilateral Agreement.

Where in The Company’s sole opinion the installation of Control Telephony is not practicable at a GB Code User’s Control Point(s), The Company shall specify in the Bilateral Agreement whether System Telephony is required. Where System Telephony is required by The Company, the GB Code User shall ensure that System Telephony is installed.

Where System Telephony is installed, GB Code Users are required to use the System Telephony with The Company in respect of those Control Point(s) for which it has been installed. Details of and relating to the System Telephony required are contained in the Bilateral Agreement.

Where Control Telephony or System Telephony is installed, routine testing of such facilities may be required by The Company (not normally more than once in any calendar month). The GB Code User and The Company shall use reasonable endeavours to agree a test programme and where The Company requests the assistance of the GB Code User in performing the agreed test programme the User shall provide such assistance. The Company requires the GB Code User to test the backup power supplies feeding its Control Telephony facilities at least once every 5 years.

Control Telephony and System Telephony shall only be used for the purposes of operational voice communication between The Company and the relevant User.

Control Telephony contains emergency calling functionality to be used for urgent operational communication only. Such functionality enables The Company and Users to utilise a priority call in the event of an emergency. The Company and GB Code Users shall only use such priority call functionality for urgent operational communications.

Technical Requirements for Control Telephony and System Telephony

Detailed information on the technical interfaces and support requirements for Control Telephony is provided in the Control Telephony Electrical Standard identified in the Annex to the General Conditions. Where additional information, or information in relation to Control Telephony applicable in Scotland, is requested by GB Code Users, this will be provided, where possible, by The Company.

System Telephony shall consist of a dedicated telephone connected to an appropriate public communications network, that shall be configured by the relevant GB Code User. The Company shall provide a dedicated free phone number (UK only), for the purposes of receiving incoming calls to The Company, which GB Code Users shall utilise for System Telephony. System Telephony shall only be utilised by The Company Control Engineer and the GB Code User’s Responsible Engineer/Operator for the purposes of operational communications.

Operational Metering
CC.6.5.6

(a) The Company or The Relevant Transmission Licensee, as applicable, shall provide system control and data acquisition (SCADA) outstation interface equipment. The GB Code User shall provide such voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the Transmission SCADA outstation interface equipment as required by The Company in accordance with the terms of the Bilateral Agreement. In the case of OTSDUW, the GB Code User shall provide such SCADA outstation interface equipment and voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the SCADA outstation interface equipment as required by The Company in accordance with the terms of the Bilateral Agreement.

(b) For the avoidance of doubt, for Active Power and Reactive Power measurements, circuit breaker and disconnector status indications from:

(i) CCGT Modules at Large Power Stations, the outputs and status indications must each be provided to The Company on an individual CCGT Unit basis. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements from Unit Transformers and/or Station Transformers must be provided.

(ii) DC Converters at DC Converter Stations and OTSDUW DC Converters, the outputs and status indications must each be provided to The Company on an individual DC Converter basis. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements from converter and/or station transformers must be provided.

(iii) Power Park Modules at Embedded Large Power Stations and at directly connected Power Stations, the outputs and status indications must each be provided to The Company on an individual Power Park Module basis. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements from station transformers must be provided.

(iv) In respect of OTSDUW Plant and Apparatus, the outputs and status indications must be provided to The Company for each piece of electrical equipment. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements at the Interface Point must be provided.

(c) For the avoidance of doubt, the requirements of CC.6.5.6(a) in the case of a Cascade Hydro Scheme will be provided for each Generating Unit forming part of that Cascade Hydro Scheme. In the case of Embedded Generating Units forming part of a Cascade Hydro Scheme the data may be provided by means other than the SCADA outstation located at the Power Station, such as, with the agreement of the Network Operator in whose system such Embedded Generating Unit is located, from the Network Operator’s SCADA system to The Company. Details of such arrangements will be contained in the relevant Bilateral Agreements between The Company and the GB Generator and the Network Operator.

(d) In the case of a Power Park Module, additional energy input signals (e.g. wind speed, and wind direction) may be specified in the Bilateral Agreement. For Power Park Modules with a Completion Date on or after 1st April 2016, a Power Available signal will also be specified in the Bilateral Agreement. The signals would be used to establish the potential level of energy input from the Intermittent Power Source for monitoring pursuant to CC.6.6.1 and Ancillary Services and will, in the case of a wind farm, be used to provide The Company with advanced warning of excess wind speed shutdown and to determine the level of Headroom available from Power Park Modules for the purposes of calculating response and reserve. For the avoidance of doubt, the Power Available signal would be automatically provided to The Company and represent the sum of the potential output of all available and operational Power Park Units within the Power Park Module. The refresh rate of the Power Available signal shall be specified in the Bilateral Agreement.
The User shall accommodate Instructor Facilities provided by The Company for the receipt of operational messages relating to System conditions.

Electronic Data Communication Facilities

(a) All BM Participants must ensure that appropriate electronic data communication facilities are in place to permit the submission of data, as required by the Grid Code, to The Company.

(b) In addition,

(1) any GB Code User that wishes to participate in the Balancing Mechanism;

or

(2) any BM Participant in respect of its BM Units at a Power Station where the Construction Agreement and/or a Bilateral Agreement has a Completion Date on or after 1 January 2013 and the BM Participant is required to provide all Part 1 System Ancillary Services in accordance with CC.8.1 (unless The Company has otherwise agreed)

must ensure that appropriate automatic logging devices are installed at the Control Points of its BM Units to submit data to and to receive instructions from The Company, as required by the Grid Code. For the avoidance of doubt, in the case of an Interconnector User, the Control Point will be at the Control Centre of the appropriate Externally Interconnected System Operator.

(c) Detailed specifications of these required electronic facilities will be provided by The Company on request and they are listed as Electrical Standards in the Annex to the General Conditions.

Facsimile Machines

(a) in the case of GB Generators, at the Control Point of each Power Station and at its Trading Point;

(b) in the case of The Company and Network Operators, at the Control Centre(s); and

(c) in the case of Non-Embedded Customers and DC Converter Station owners at the Control Point.

Each GB Code User shall notify, prior to connection to the System of the GB Code User’s Plant and Apparatus, The Company of its or their telephone number or numbers, and will notify The Company of any changes. Prior to connection to the System of the GB Code User’s Plant and Apparatus, The Company shall notify each GB Code User of the telephone number or numbers of its facsimile machine or machines and will notify any changes.

Busbar Voltage

The Relevant Transmission Licensee shall, subject as provided below, provide each GB Generator or DC Converter Station owner at each Grid Entry Point where one of its Power Stations or DC Converter Stations is connected with appropriate voltage signals to enable the GB Generator or DC Converter Station owner to obtain the necessary information to permit its Gensets or DC Converters to be Synchronised to the National Electricity Transmission System. The term “voltage signal” shall mean in this context, a point of connection on (or wire or wires from) a relevant part of Transmission Plant and/or Apparatus at the Grid Entry Point, to which the GB Generator or DC Converter Station owner, with The Company’s agreement (not to be unreasonably withheld) in relation to the Plant and/or Apparatus to be attached, will be able to attach its Plant and/or Apparatus (normally a wire or wires) in order to obtain measurement outputs in relation to the busbar.

Bilingual Message Facilities
(a) A Bilingual Message Facility is the method by which the User’s Responsible Engineer/Operator, the Externally Interconnected System Operator and The Company’s Control Engineers communicate clear and unambiguous information in two languages for the purposes of control of the Total System in both normal and emergency operating conditions.

(b) A Bilingual Message Facility, where required, will provide up to two hundred pre-defined messages with up to five hundred and sixty characters each. A maximum of one minute is allowed for the transmission to, and display of, the selected message at any destination. The standard messages must be capable of being displayed at any combination of locations and can originate from any of these locations. Messages displayed in the UK will be displayed in the English language.

(c) Detailed information on a Bilingual Message Facility and suitable equipment required for individual GB Code User applications will be provided by The Company upon request.

CC.6.6 System Monitoring

CC.6.6.1 Monitoring equipment is provided on the National Electricity Transmission System to enable The Company to monitor its power system dynamic performance conditions. Where this monitoring equipment requires voltage and current signals on the Generating Unit (other than Power Park Unit), DC Converter or Power Park Module circuit from the GB Code User or from OTSDUW Plant and Apparatus, The Company will inform the GB Code User and they will be provided by the GB Code User with both the timing of the installation of the equipment for receiving such signals and its exact position being agreed (the GB Code User’s agreement not to be unreasonably withheld) and the costs being dealt with, pursuant to the terms of the Bilateral Agreement.

CC.6.6.2 For all on site monitoring by The Company of witnessed tests pursuant to the CP or OC5 the GB Code User shall provide suitable test signals as outlined in OC5.A.1.

CC.6.6.2.1 The signals which shall be provided by the GB Code User to The Company for onsite monitoring shall be of the following resolution, unless otherwise agreed by The Company:

(i) 1 Hz for reactive range tests
(ii) 10 Hz for frequency control tests
(iii) 100 Hz for voltage control tests

CC.6.6.2.2 The GB Code User will provide all relevant signals for this purpose in the form of d.c. voltages within the range -10V to +10V. In exceptional circumstances, some signals may be accepted as d.c. voltages within the range -60V to +60V with prior agreement between the GB Code User and The Company. All signals shall:

(i) in the case of an Onshore Power Park Module, DC Converter Station or Synchronous Generating Unit, be suitably terminated in a single accessible location at the GB Generator or DC Converter Station owner’s site.

(ii) in the case of an Offshore Power Park Module and OTSDUW Plant and Apparatus, be transmitted onshore without 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 be suitably terminated in a single robust location normally located at or near the onshore Interface Point of the Offshore Transmission System to which it is connected.

CC.6.6.2.3 All signals shall be suitably scaled across the range. The following scaling would (unless The Company notify the GB Code User otherwise) be acceptable to The Company:

(a) 0MW to Registered Capacity or Interface Point Capacity 0-8V dc
(b) Maximum leading Reactive Power to maximum lagging Reactive Power -8 to 8V dc
(c) 48 – 52Hz as -8 to 8V dc
(d) Nominal terminal or connection point voltage -10% to +10% as -8 to 8V dc
CC.6.6.2.4 The GB Code User shall provide to The Company a 230V power supply adjacent to the signal terminal location.

CC.7 SITE RELATED CONDITIONS
CC.7.1 Not used.
CC.7.2 Responsibilities For Safety
CC.7.2.1 Any User entering and working on its Plant and/or Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site will work to the Safety Rules of the Relevant Transmission Licensee, as advised by The Company.

CC.7.2.2 For User Sites, The Company shall procure that the Relevant Transmission Licensee entering and working on Transmission Plant and/or Apparatus on a User Site will work to the User's Safety Rules.

CC.7.2.3 A User may, with a minimum of six weeks notice, apply to The Company for permission to work according to that Users own Safety Rules when working on its Plant and/or Apparatus on a Transmission Site rather than those set out in CC.7.2.1. If The Company is of the opinion that the User's Safety Rules provide for a level of safety commensurate with those set out in CC.7.2.1, The Company will notify the User, in writing, that, with effect from the date requested by the User, the User may use its own Safety Rules when working on its Plant and/or Apparatus on the Transmission Site. In forming its opinion, The Company will seek the opinion of the Relevant Transmission Licensee. Until receipt of such written approval from The Company, the GB Code User will continue to use the Safety Rules as set out in CC.7.2.1.

CC.7.2.4 In the case of a User Site, The Company may, with a minimum of six weeks notice, apply to a User for permission for the Relevant Transmission Licensee to work according to the Relevant Transmission Licensee’s Safety Rules when working on Transmission Plant and/or Apparatus on that User Site, rather than the User's Safety Rules. If the User is of the opinion that the Relevant Transmission Licensee’s Safety Rules provide for a level of safety commensurate with that of the User's Safety Rules, it will notify The Company, in writing, that, with effect from the date requested by The Company, that the Relevant Transmission Licensee may use its own Safety Rules when working on its Transmission Plant and/or Apparatus on that User’s Site. Until receipt of such written approval from the User, The Company shall procure that the Relevant Transmission Licensee shall continue to use the User’s Safety Rules.

CC.7.2.5 For a Transmission Site, if The Company gives its approval for the User's Safety Rules to apply to the User when working on its Plant and/or Apparatus, that does not imply that the User's Safety Rules will apply to entering the Transmission Site and access to the User’s Plant and/or Apparatus on that Transmission Site. Bearing in mind the Relevant Transmission Licensee’s responsibility for the whole Transmission Site, entry and access will always be in accordance with the Relevant Transmission Licensee’s site access procedures. For a User Site, if the User gives its approval for Relevant Transmission Licensee Safety Rules to apply to the Relevant Transmission Licensee when working on its Plant and Apparatus, that does not imply that the Relevant Transmission Licensee’s Safety Rules will apply to entering the User Site, and access to the Transmission Plant and Apparatus on that User Site. Bearing in mind the User's responsibility for the whole User Site, entry and access will always be in accordance with the User’s site access procedures.

CC.7.2.6 For User Sites, Users shall notify The Company of any Safety Rules that apply to the Relevant Transmission Licensee’s staff working on User Sites. The Company shall procure that the Relevant Transmission Licensee shall notify Users of any Safety Rules that apply to the User’s staff working on the Transmission Site.

CC.7.2.7 Each Site Responsibility Schedule must have recorded on it the Safety Rules which apply to each item of Plant and/or Apparatus.
CC.7.2.8 In the case of OTSUA a User Site or Transmission Site shall, for the purposes of this CC.7.2, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

CC.7.3 Site Responsibility Schedules

CC.7.3.1 In order to inform site operational staff and The Company’s Control Engineers of agreed responsibilities for Plant and/or Apparatus at the operational interface, a Site Responsibility Schedule shall be produced for Connection Sites (and in the case of OTSUA, until the OTSUA Transfer Time, Interface Sites) for The Company, the Relevant Transmission Licensee and Users with whom they interface.

CC.7.3.2 The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix 1.

CC.7.4 Operation And Gas Zone Diagrams

Operation Diagrams

CC.7.4.1 An Operation Diagram shall be prepared for each Connection Site at which a Connection Point exists (and in the case of OTSDUW Plant and Apparatus, by User’s for each Interface Point) using, where appropriate, the graphical symbols shown in Part 1A of Appendix 2. Users should also note that the provisions of OC11 apply in certain circumstances.

CC.7.4.2 The Operation Diagram shall include all HV Apparatus and the connections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in OC11. At those Connection Sites (or in the case of OTSDUW Plant and Apparatus, Interface Points) where gas-insulated metal enclosed switchgear and/or other gas-insulated HV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects gas-zone boundaries. The nomenclature used shall conform with that used on the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, Interface Point and circuit). The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of HV Apparatus and related Plant.

CC.7.4.3 A non-exhaustive guide to the types of HV Apparatus to be shown in the Operation Diagram is shown in Part 2 of Appendix 2, together with certain basic principles to be followed unless equivalent principles are approved by The Company.

Gas Zone Diagrams

CC.7.4.4 A Gas Zone Diagram shall be prepared for each Connection Site at which a Connection Point (and in the case of OTSDUW Plant and Apparatus, by User’s for each Interface Point) exists where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised. They shall use, where appropriate, the graphical symbols shown in Part 1B of Appendix 2.

CC.7.4.5 The nomenclature used shall conform with that used in the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, relevant Interface Point and circuit).

CC.7.4.6 The basic principles set out in Part 2 of Appendix 2 shall be followed in the preparation of Gas Zone Diagrams unless equivalent principles are approved by The Company.

Preparation of Operation and Gas Zone Diagrams for Users’ Sites and Transmission Interface Sites

CC.7.4.7 In the case of a User Site, the User shall prepare and submit to The Company, an Operation Diagram for all HV Apparatus on the User side of the Connection Point (and in the case of OTSDUW Plant and Apparatus, on what will be the Offshore Transmission side of the Connection Point and the Interface Point) and The Company shall provide the User with an Operation Diagram for all HV Apparatus on the Transmission side of the Connection Point (and in the case of OTSDUW Plant and Apparatus on what will be the Onshore Transmission side of the Interface Point), in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement.
The User will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram and The Company Operation Diagram, a composite Operation Diagram for the complete Connection Site (and in the case of OTSDUW Plant and Apparatus, Interface Point), also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

The provisions of CC.7.4.7 and CC.7.4.8 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

Preparation of Operation and Gas Zone Diagrams for Transmission Sites

In the case of an Transmission Site, the User shall prepare and submit to The Company an Operation Diagram for all HV Apparatus on the User side of the Connection Point, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

The Company will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram, a composite Operation Diagram for the complete Connection Site, also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

The provisions of CC.7.4.10 and CC.7.4.11 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

Changes to Operation and Gas Zone Diagrams

When the Relevant Transmission Licensee has decided that it wishes to install new HV Apparatus or it wishes to change the existing numbering or nomenclature of Transmission HV Apparatus at a Transmission Site, The Company, in coordination with the Relevant Transmission Licensee will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to each such User a revised Operation Diagram of that Transmission Site, incorporating the new Transmission HV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be. OC11 is also relevant to certain Apparatus.

When a User has decided that it wishes to install new HV Apparatus, or it wishes to change the existing numbering or nomenclature of its HV Apparatus at its User Site, the User will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to The Company a revised Operation Diagram of that User Site incorporating the new User HV Apparatus to be installed and its numbering and nomenclature or the changes as the case may be. OC11 is also relevant to certain Apparatus.

The provisions of CC.7.4.13.1 and CC.7.4.13.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is installed.

Validity

(a) The composite Operation Diagram prepared by The Company or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Connection Site, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

(b) The composite Operation Diagram prepared by The Company or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

(c) An equivalent rule shall apply for Gas Zone Diagrams where they exist for a Connection Site.
In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this CC.7.4, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System and references to HV Apparatus in this CC.7.4 shall include references to HV OTSUA.

**Site Common Drawings**

**Site Common Drawings** will be prepared for each Connection Site (and in the case of OTSDUW, each Interface Point) and will include Connection Site (and in the case of OTSDUW, Interface Point) layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

**Preparation of Site Common Drawings for a User Site and Transmission Interface Site**

In the case of a User Site, The Company shall prepare and submit to the User, Site Common Drawings for the Transmission side of the Connection Point (and in the case of OTSDUW Plant and Apparatus, on what will be the Onshore Transmission side of the Interface Point,) and the User shall prepare and submit to The Company, Site Common Drawings for the User side of the Connection Point (and in the case of OTSDUW, on what will be the Offshore Transmission side of the Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

The User will then prepare, produce and distribute, using the information submitted on the Transmission Site Common Drawings, Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

**Preparation of Site Common Drawings for a Transmission Site**

In the case of a Transmission Site, the User will prepare and submit to The Company Site Common Drawings for the User side of the Connection Point in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

The Company will then prepare, produce and distribute, using the information submitted in the User’s Site Common Drawings, Site Common Drawings for the complete Connection Site in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

When a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:

(a) if it is a User Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and

(b) if it is a Transmission Site, as soon as reasonably practicable, prepare and submit to The Company revised Site Common Drawings for the User side of the Connection Point (and in the case of OTSDUW, Interface Point) and The Company will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the User’s Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in the User’s reasonable opinion the change can be dealt with by it notifying The Company in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

When The Company becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:

(a) if it is a Transmission Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and
(b) if it is a User Site, as soon as reasonably practicable, prepare and submit to the User revised Site Common Drawings for the Transmission side of the Connection Point (in the case of OTSDUW, Interface Point) and the User will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the Transmission Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in The Company’s reasonable opinion the change can be dealt with by it notifying the User in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

Validity

CC.7.5.8 (a) The Site Common Drawings for the complete Connection Site prepared by the User or The Company, as the case may be, will be the definitive Site Common Drawings for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the Site, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

(b) The Site Common Drawing prepared by The Company or the User, as the case may be, will be the definitive Site Common Drawing for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

CC.7.5.9 In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this CC.7.5, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

CC.7.6 Access

CC.7.6.1 The provisions relating to access to Transmission Sites by Users, and to Users’ Sites by Relevant Transmission Licensees, are set out in each Interface Agreement (or in the case of Interfaces Sites prior to the OTSUA Transfer Time agreements in similar form) with, the Relevant Transmission Licensee and each User.

CC.7.6.2 In addition to those provisions, where a Transmission Site contains exposed HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by the Relevant Transmission Licensee.

CC.7.6.3 The procedure for applying for an Authority for Access is contained in the Interface Agreement.

CC.7.7 Maintenance Standards

CC.7.7.1 It is the User’s responsibility to ensure that all its Plant and Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site is tested and maintained adequately for the purpose for which it is intended, and to ensure that it does not pose a threat to the safety of any Transmission Plant, Apparatus or personnel on the Transmission Site. The Company will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus at any time.

CC.7.7.2 For User Sites, The Company shall procure that the Relevant Transmission Licensee has a responsibility to ensure that all Transmission Plant and Apparatus on a User Site is tested and maintained adequately for the purposes for which it is intended and to ensure that it does not pose a threat to the safety of any User’s Plant, Apparatus or personnel on the User Site. The User will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus on its User Site at any time.

CC.7.8 Site Operational Procedures
CC.7.8.1 Where there is an interface with National Electricity Transmission System, The Company and Users, must make available staff to take necessary Safety Precautions and carry out operational duties as may be required to enable work/testing to be carried out and for the operation of Plant and Apparatus (including, prior to the OTSUA Transfer Time, any OTSUA) connected to the Total System.

CC.7.9 GB Generators, DC Converter Station owners and BM Participants shall provide a Control Point.

a) In the case of GB Generators and DC Converter Station owners, for each Power Station or DC Converter Station directly connected to the National Electricity Transmission System and for each Embedded Large Power Station or Embedded DC Converter Station, the Control Point shall receive and act upon instructions pursuant to OC7 and BC2 at all times that Generating Units or Power Park Modules at the Power Station are generating or available to generate or DC Converters at the DC Converter Station are importing or exporting or available to do so. In the case of all BM Participants, the Control Point shall be continuously staffed except where the Bilateral Agreement specifies that compliance with BC2 is not required, in which case the Control Point shall be staffed between the hours of 0800 and 1800 each day.

b) In the case of BM Participants, the BM Participant’s Control Point shall be capable of receiving and acting upon instructions from The Company. The Company will normally issue instructions via automatic logging devices in accordance with the requirements of CC.6.5.8(b).

Where the BM Participant’s Plant and Apparatus does not respond to an instruction from The Company via automatic logging devices, or where it is not possible for The Company to issue the instruction via automatic logging devices, The Company shall issue the instruction by telephone.

In the case of BM Participants who own and/or operate a Power Station or DC Converter Station with an aggregated Registered Capacity or BM Participants with BM Units with an aggregated Demand Capacity per Control Point of less than 50MW, or, where a site is not part of a Virtual Lead Party as defined in the BSC, a Registered Capacity or Demand Capacity per site of less than 10MW:

a) where this situation arises, a representative of the BM Participant is required to be available to respond to instructions from The Company via the Control Telephony or System Telephony system, as provided for in CC.6.5.4, between the hours of 0800-1800 each day.

b) Outside the hours of 0800-1800 each day, the requirements of BC2.9.7 shall apply.

For the avoidance of doubt, BM Participants who are unable to provide Control Telephony and do not have a continuously staffed Control Point may be unable to act as a Defence Service Provider and shall be unable to act as a Restoration Service Provider or Black Start Service Provider where these require Control Telephony or a Control Point in respect of the specification of any such services falling into these categories.

CC.8 ANCILLARY SERVICES

CC.8.1 System Ancillary Services

The CC’s contain requirements for the capability for certain Ancillary Services, which are needed for System reasons (“System Ancillary Services”). There follows a list of these System Ancillary Services, together with the paragraph number of the CC (or other part of the Grid Code) in which the minimum capability is required or referred to. The list is divided into two categories: Part 1 lists the System Ancillary Services which
(a) **GB Generators** in respect of **Large Power Stations** are obliged to provide (except **GB Generators** in respect of **Large Power Stations** which have a **Registered Capacity** of less than 50MW and comprise **Power Park Modules**); and, 

(b) **GB Generators** in respect of **Large Power Stations** with a **Registered Capacity** of less than 50MW and comprise **Power Park Modules** are obliged to provide in respect of **Reactive Power** only; and, 

(c) **DC Converter Station** owners are obliged to have the capability to supply; and 

(d) **GB Generators** in respect of **Medium Power Stations** (except **Embedded Medium Power Stations**) are obliged to provide in respect of **Reactive Power only**:

and Part 2 lists the **System Ancillary Services** which **GB Generators** will provide only if agreement to provide them is reached with **The Company**:

**Part 1**

(a) **Reactive Power** supplied (in accordance with CC.6.3.2) otherwise than by means of synchronous or static compensators (except in the case of a **Power Park Module** where synchronous or static compensators within the **Power Park Module** may be used to provide **Reactive Power**) 

(b) **Frequency Control** by means of **Frequency sensitive generation** - CC.6.3.7 and BC3.5.1

**Part 2**

(c) **Frequency Control** by means of **Fast Start** - CC.6.3.14

(d) **Black Start Capability** - CC.6.3.5

(e) **System to Generator Operational Intertripping**

**CC.8.2 Commercial Ancillary Services**

Other **Ancillary Services** are also utilised by **The Company** in operating the **Total System** if these have been agreed to be provided by a **GB Code User** (or other person) 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 Ancillary Services**"). The capability for these **Commercial Ancillary Services** is set out in the relevant **Ancillary Services Agreement** or **Bilateral Agreement** (as the case may be).
APPENDIX 1 - SITE RESPONSIBILITY SCHEDULES

FORMAT, PRINCIPLES AND BASIC PROCEDURE TO BE USED IN THE PREPARATION OF SITE RESPONSIBILITY SCHEDULES

CC.A.1.1 Principles

Types of Schedules

CC.A.1.1.1 At all Complexes (which in the context of this CC shall include, Interface Sites until the OTSUA Transfer Time) the following Site Responsibility Schedules shall be drawn up using the relevant proforma attached or with such variations as may be agreed between The Company and Users, but in the absence of agreement the relevant proforma attached will be used. In addition, in the case of OTSDUW Plant and Apparatus, and in readiness for the OTSUA Transfer Time, the User shall provide The Company with the necessary information such that Site Responsibility Schedules in this form can be prepared by the Relevant Transmission Licensees for the Transmission Interface Site:

(a) Schedule of HV Apparatus

(b) Schedule of Plant, LV/MV Apparatus, services and supplies;

(c) Schedule of telecommunications and measurements Apparatus.

Other than at Generating Unit, DC Converter, Power Park Module and Power Station locations, the schedules referred to in (b) and (c) may be combined.

New Connection Sites

CC.A.1.1.2 In the case of a new Connection Site each Site Responsibility Schedule for a Connection Site shall be prepared by The Company in consultation with relevant GB Code Users at least 2 weeks prior to the Completion Date (or, where the OTSUA is to become Operational prior to the OTSUA Transfer Time, an alternative date) under the Bilateral Agreement and/or Construction Agreement for that Connection Site (which may form part of a Complex). In the case of a new Interface Site where the OTSUA is to become Operational prior to the OTSUA Transfer Time each Site Responsibility Schedule for an Interface Site shall be prepared by The Company in consultation with relevant GB Code Users at least 2 weeks prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement for that Interface Site (which may form part of a Complex) (and references to and requirements placed on “Connection Site” in this CC shall also be read as “Interface Site” where the context requires and until the OTSUA Transfer Time). Each GB Code User shall, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement, provide information to The Company to enable it to prepare the Site Responsibility Schedule.

Sub-division

CC.A.1.1.3 Each Site Responsibility Schedule will be subdivided to take account of any separate Connection Sites on that Complex.

Scope

CC.A.1.1.4 Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus:

(a) Plant/Apparatus ownership;

(b) Site Manager (Controller) (except in the case of Plant/Apparatus located in SPT’s Transmission Area);

(c) Safety issues comprising applicable Safety Rules and Control Person or other responsible person (Safety Co-ordinator), or such other person who is responsible for safety;

(d) Operations issues comprising applicable Operational Procedures and Control Engineer;
(e) Responsibility to undertake statutory inspections, fault investigation and maintenance.

Each Connection Point shall be precisely shown.

**Detail**

CC.A.1.1.5

(a) In the case of Site Responsibility Schedules referred to in CC.A.1.1.1(b) and (c), with the exception of Protection Apparatus and Intertrip Apparatus operation, it will be sufficient to indicate the responsible User or Transmission Licensee, as the case may be.

(b) In the case of the Site Responsibility Schedule referred to in CC.A.1.1.1(a) and for Protection Apparatus and Intertrip Apparatus, the responsible management unit must be shown in addition to the User or Transmission Licensee, as the case may be.

CC.A.1.1.6

The HV Apparatus Site Responsibility Schedule for each Connection Site must include lines and cables emanating from or traversing¹ the Connection Site.

**Issue Details**

CC.A.1.1.7

Every page of each Site Responsibility Schedule shall bear the date of issue and the issue number.

**Accuracy Confirmation**

CC.A.1.1.8

When a Site Responsibility Schedule is prepared it shall be sent by The Company to the Users involved for confirmation of its accuracy.

CC.A.1.1.9

The Site Responsibility Schedule shall then be signed on behalf of The Company by its Responsible Manager (see CC.A.1.1.16) and on behalf of each User involved by its Responsible Manager (see CC.A.1.1.16), by way of written confirmation of its accuracy. The Site Responsibility Schedule will also be signed on behalf of the Relevant Transmission Licensee by its Responsible Manager.

**Distribution and Availability**

CC.A.1.1.10

Once signed, two copies will be distributed by The Company, not less than two weeks prior to its implementation date, to each User which is a party on the Site Responsibility Schedule, accompanied by a note indicating the issue number and the date of implementation.

CC.A.1.1.11

The Company and Users must make the Site Responsibility Schedules readily available to operational staff at the Complex and at the other relevant control points.

**Alterations to Existing Site Responsibility Schedules**

CC.A.1.1.12

Without prejudice to the provisions of CC.A.1.1.15 which deals with urgent changes, when a User identified on a Site Responsibility Schedule becomes aware that an alteration is necessary, it must inform The Company immediately and in any event 8 weeks prior to any change taking effect (or as soon as possible after becoming aware of it, if less than 8 weeks remain when the User becomes aware of the change). This will cover the commissioning of new Plant and/or Apparatus at the Connection Site, whether requiring a revised Bilateral Agreement or not, de-commissioning of Plant and/or Apparatus, and other changes which affect the accuracy of the Site Responsibility Schedule.

CC.A.1.1.13

Where The Company has been informed of a change by an GB Code User, or itself proposes a change, it will prepare a revised Site Responsibility Schedule by not less than six weeks prior to the change taking effect (subject to it having been informed or knowing of the change eight weeks prior to that time) and the procedure set out in CC.A.1.1.8 shall be followed with regard to the revised Site Responsibility Schedule.

¹ Details of circuits traversing the Connection Site are only needed from the date which is the earlier of the date when the Site Responsibility Schedule is first updated and 15th October 2004. In Scotland or Offshore, from a date to be agreed between The Company and the Relevant Transmission Licensee.
CC.A 1.1.14  The revised **Site Responsibility Schedule** shall then be signed in accordance with the procedure set out in CC.A.1.1.9 and distributed in accordance with the procedure set out in CC.A.1.1.10, accompanied by a note indicating where the alteration(s) has/have been made, the new issue number and the date of implementation.
Urgent Changes

CC.A.1.1.15 When an **GB Code User** identified on a **Site Responsibility Schedule**, or **The Company**, as the case may be, becomes aware that an alteration to the **Site Responsibility Schedule** is necessary urgently to reflect, for example, an emergency situation which has arisen outside its control, the **GB Code User** shall notify **The Company**, or **The Company** shall notify the **GB Code User**, as the case may be, immediately and will discuss:

(a) what change is necessary to the **Site Responsibility Schedule**;
(b) whether the **Site Responsibility Schedule** is to be modified temporarily or permanently;
(c) the distribution of the revised **Site Responsibility Schedule**.

**The Company** will prepare a revised **Site Responsibility Schedule** as soon as possible, and in any event within seven days of it being informed of or knowing the necessary alteration. The **Site Responsibility Schedule** will be confirmed by **GB Code Users** and signed on behalf of **The Company** and **GB Code Users** and the **Relevant Transmission Licensee** (by the persons referred to in CC.A.1.1.9) as soon as possible after it has been prepared and sent to **GB Code Users** for confirmation.

Responsible Managers

CC.A.1.1.16 Each **GB Code User** shall, prior to the **Completion Date** under each **Bilateral Agreement** and/or **Construction Agreement**, supply to **The Company** a list of Managers who have been duly authorised to sign **Site Responsibility Schedules** on behalf of the **GB Code User** and **The Company** shall, prior to the **Completion Date** under each **Bilateral Agreement** and/or **Construction Agreement**, supply to that **GB Code User** the name of the **Relevant Transmission Licensee’s Responsible Manager** and each shall supply to the other any changes to such list six weeks before the change takes effect where the change is anticipated, and as soon as possible after the change, where the change was not anticipated.

De-commissioning of Connection Sites

CC.A.1.1.17 Where a **Connection Site** is to be de-commissioned, whichever of **The Company** or the **GB Code User** who is initiating the de-commissioning must contact the other to arrange for the **Site Responsibility Schedule** to be amended at the relevant time.
PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

------------------------------------------ AREA

COMPLEX: _____________________________ SCHEDULE: ______________

CONNECTION SITE: _____________________

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<th>CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY COORDINATOR)</th>
<th>OPERATIONAL PROCEDURES</th>
<th>CONTROL OR OTHER RESPONSIBLE ENGINEER</th>
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PAGE: _______ ISSUE NO: _______________ DATE: _______________
# PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

## AREA

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**SCHEDULE:**

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**NOTES:**

**SIGNED:**

**NAME:**

**COMPANY:**

**DATE:**

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**SIGNED:**

**NAME:**

**COMPANY:**

**DATE:**

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**DATE:**

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09 March 2022
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PART 2 - NON-EXHAUSTIVE LIST OF APPARATUS
TO BE INCLUDED ON OPERATION DIAGRAMS

Basic Principles

(1) Where practicable, all the HV Apparatus on any Connection Site shall be shown on one Operation Diagram. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the Connection Site.

(2) Where more than one Operation Diagram is unavoidable, duplication of identical information on more than one Operation Diagram must be avoided.

(3) The Operation Diagram must show accurately the current status of the Apparatus e.g. whether commissioned or decommissioned. Where decommissioned, the associated switchbay will be labelled "spare bay".

(4) Provision will be made on the Operation Diagram for signifying approvals, together with provision for details of revisions and dates.

(5) Operation Diagrams will be prepared in A4 format or such other format as may be agreed with The Company.

(6) The Operation Diagram should normally be drawn single line. However, where appropriate, detail which applies to individual phases shall be shown. For example, some HV Apparatus is numbered individually per phase.

Apparatus To Be Shown On Operation Diagram

(1) Busbars
(2) Circuit Breakers
(3) Disconnector (Isolator) and Switch Disconnectors (Switching Isolators)
(4) Disconnectors (Isolators) - Automatic Facilities
(5) Bypass Facilities
(6) Earthing Switches
(7) Maintenance Earths
(8) Overhead Line Entries
(9) Overhead Line Traps
(10) Cable and Cable Sealing Ends
(11) Generating Unit
(12) Generator Transformers
(13) Generating Unit Transformers, Station Transformers, including the lower voltage circuit-breakers.
(14) Synchronous Compensators
(15) Static Variable Compensators
(16) Capacitors (including Harmonic Filters)
(17) Series or Shunt Reactors (Referred to as “Inductors” at nuclear power station sites)
(18) Supergrid and Grid Transformers
(19) Tertiary Windings
(20) Earthing and Auxiliary Transformers
(21) Three Phase VT's
(22) Single Phase VT & Phase Identity
(23) High Accuracy VT and Phase Identity
(24) Surge Arrestors/Diverters
(25) Neutral Earthing Arrangements on HV Plant
(26) Fault Throwing Devices
(27) Quadrature Boosters
(28) Arc Suppression Coils
(29) Single Phase Transformers (BR) Neutral and Phase Connections
(30) Current Transformers (where separate plant items)
(31) Wall Bushings
(32) Combined VT/CT Units
(33) Shorting and Discharge Switches
(34) Thyristor
(35) Resistor with Inherent Non-Linear Variability, Voltage Dependent
(36) Gas Zone
APPENDIX 3 - MINIMUM FREQUENCY RESPONSE REQUIREMENT PROFILE AND OPERATING RANGE FOR NEW POWER STATIONS AND DC CONVERTER STATIONS

CC.A.3.1 Scope

The Frequency response capability is defined in terms of Primary Response, Secondary Response and High Frequency Response. This appendix defines the minimum Frequency response requirement profile for:

(a) each Onshore Generating Unit and/or CCGT Module which has a Completion Date after 1 January 2001 in England and Wales and 1 April 2005 in Scotland and Offshore Generating Unit in a Large Power Station,

(b) each DC Converter at a DC Converter Station which has a Completion Date on or after 1 April 2005 or each Offshore DC Converter which is part of a Large Power Station.

(c) each Onshore Power Park Module in England and Wales with a Completion Date on or after 1 January 2006.

(d) each Onshore Power Park Module in operation in Scotland after 1 January 2006 with a Completion Date after 1 April 2005 and in Power Stations with a Registered Capacity of 50MW or more.

(e) each Offshore Power Park Module in a Large Power Station with a Registered Capacity of 50MW or more.

For the avoidance of doubt, this appendix does not apply to:

(i) Generating Units and/or CCGT Modules which have a Completion Date before 1 January 2001 in England and Wales and before 1 April 2005 in Scotland.

(ii) DC Converters at a DC Converter Station which have a Completion Date before 1 April 2005.

(iii) Power Park Modules in England and Wales with a Completion Date before 1 January 2006.

(iv) Power Park Modules in operation in Scotland before 1 January 2006.

(v) Power Park Modules in Scotland with a Completion Date before 1 April 2005.

(vi) Power Park Modules in Power Stations with a Registered Capacity less than 50MW.

(vii) Small Power Stations or individually to Power Park Units; or.

(viii) an OTSDUW DC Converter where the Interface Point Capacity is less than 50MW.

OTSDUW Plant and Apparatus should facilitate the delivery of Frequency response services provided by Offshore Generating Units and Offshore Power Park Modules at the Interface Point.

The functional definition provides appropriate performance criteria relating to the provision of Frequency control by means of Frequency sensitive generation in addition to the other requirements identified in CC.6.3.7.

In this Appendix 3 to the CC, for a CCGT Module or a Power Park Module with more than one Generating Unit, the phrase Minimum Generation applies to the entire CCGT Module or Power Park Module operating with all Generating Units Synchronised to the System.

The minimum Frequency response requirement profile is shown diagrammatically in Figure CC.A.3.1. The capability profile specifies the minimum required levels of Primary Response, Secondary Response and High Frequency Response throughout the normal plant operating range. The definitions of these Frequency response capabilities are illustrated diagrammatically in Figures CC.A.3.2 & CC.A.3.3.
CC.A.3.2  
Plant Operating Range

The upper limit of the operating range is the Registered Capacity of the Generating Unit or CCGT Module or DC Converter or Power Park Module.

The Minimum Generation level may be less than, but must not be more than, 65% of the Registered Capacity. Each Generating Unit and/or CCGT Module and/or Power Park Module and/or DC Converter must be capable of operating satisfactorily down to the Designed Minimum Operating Level as dictated by System operating conditions, although it will not be instructed to below its Minimum Generation level. If a Generating Unit or CCGT Module or Power Park Module or DC Converter is operating below Minimum Generation because of high System Frequency, it should recover adequately to its Minimum Generation level as the System Frequency returns to Target Frequency so that it can provide Primary and Secondary Response from Minimum Generation if the System Frequency continues to fall. For the avoidance of doubt, under normal operating conditions steady state operation below Minimum Generation is not expected. The Designed Minimum Operating Level must not be more than 55% of Registered Capacity.

In the event of a Generating Unit or CCGT Module or Power Park Module or DC Converter load rejecting down to no less than its Designed Minimum Operating Level it should not trip as a result of automatic action as detailed in BC3.7. If the load rejection is to a level less than the Designed Minimum Operating Level then it is accepted that the condition might be so severe as to cause it to be disconnected from the System.

CC.A.3.3  
Minimum Frequency Response Requirement Profile

Figure CC.A.3.1 shows the minimum Frequency response requirement profile diagrammatically for a 0.5 Hz change in Frequency. The percentage response capabilities and loading levels are defined on the basis of the Registered Capacity of the Generating Unit or CCGT Module or Power Park Module or DC Converter. Each Generating Unit and/or CCGT Module and/or Power Park Module and/or DC Converter must be capable of operating in a manner to provide Frequency response at least to the solid boundaries shown in the figure. If the Frequency response capability falls within the solid boundaries, the Generating Unit or CCGT Module or Power Park Module or DC Converter is providing response below the minimum requirement which is not acceptable. Nothing in this appendix is intended to prevent a Generating Unit or CCGT Module or Power Park Module or DC Converter from being designed to deliver a Frequency response in excess of the identified minimum requirement.

The Frequency response delivered for Frequency deviations of less than 0.5 Hz should be no less than a figure which is directly proportional to the minimum Frequency response requirement for a Frequency deviation of 0.5 Hz. For example, if the Frequency deviation is 0.2 Hz, the corresponding minimum Frequency response requirement is 40% of the level shown in Figure CC.A.3.1. The Frequency response delivered for Frequency deviations of more than 0.5 Hz should be no less than the response delivered for a Frequency deviation of 0.5 Hz.

Each Generating Unit and/or CCGT Module and/or Power Park Module and/or DC Converter must be capable of providing some response, in keeping with its specific operational characteristics, when operating between 95% to 100% of Registered Capacity as illustrated by the dotted lines in Figure CC.A.3.1.

At the Minimum Generation level, each Generating Unit and/or CCGT Module and/or Power Park Module and/or DC Converter is required to provide high and low frequency response depending on the System Frequency conditions. Where the Frequency is high, the Active Power output is therefore expected to fall below the Minimum Generation level.

The Designed Minimum Operating Level is the output at which a Generating Unit and/or CCGT Module and/or Power Park Module and/or DC Converter has no High Frequency Response capability. It may be less than, but must not be more than, 55% of the Registered Capacity. This implies that a Generating Unit or CCGT Module or Power Park Module or DC Converter is not obliged to reduce its output to below this level unless the Frequency is at or above 50.5 Hz (cf BC3.7).
Testing of Frequency Response Capability

The response capabilities shown diagrammatically in Figure CC.A.3.1 are measured by taking the responses as obtained from some of the dynamic response tests specified by The Company and carried out by GB Generators and DC Converter Station owners for compliance purposes and to validate the content of Ancillary Services Agreements using an injection of a Frequency change to the plant control system (i.e. governor and load controller). The injected signal is a linear ramp from zero to 0.5 Hz Frequency change over a ten second period, and is sustained at 0.5 Hz Frequency change thereafter, as illustrated diagrammatically in figures CC.A.3.2 and CC.A.3.3. In the case of an Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded DC Converter Station not subject to a Bilateral Agreement, The Company may require the Network Operator within whose System the Embedded Medium Power Station or Embedded DC Converter Station is situated, to ensure that the Embedded Person performs the dynamic response tests reasonably required by The Company in order to demonstrate compliance within the relevant requirements in the CC.

The Primary Response capability (P) of a Generating Unit or a CCGT Module or Power Park Module or DC Converter is the minimum increase in Active Power output between 10 and 30 seconds after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2. This increase in Active Power output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the Frequency fall as illustrated by the response from Figure CC.A.3.2.

The Secondary Response capability (S) of a Generating Unit or a CCGT Module or Power Park Module or DC Converter is the minimum increase in Active Power output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated diagrammatically in Figure CC.A.3.2.

The High Frequency Response capability (H) of a Generating Unit or a CCGT Module or Power Park Module or DC Converter is the decrease in Active Power output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure CC.A.3.3. This reduction in Active Power output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the Frequency rise as illustrated by the response in Figure CC.A.3.2.

Repeatability Of Response

When a Generating Unit or CCGT Module or Power Park Module or DC Converter has responded to a significant Frequency disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than 20 minutes after the initial change of System Frequency arising from the Frequency disturbance.
Figure CC.A.3.1 - Minimum Frequency Response Requirement Profile for a 0.5 Hz frequency change from Target Frequency.
Figure CC.A.3.2 - Interpretation of Primary and Secondary Response Values

Figure CC.A.3.3 - Interpretation of High Frequency Response Values
APPENDIX 4 - FAULT RIDE THROUGH REQUIREMENTS

APPENDIX 4A - FAULT RIDE THROUGH REQUIREMENTS FOR ONSHORE SYNCHRONOUS GENERATING UNITS, ONSHORE POWER PARK MODULES, ONSHORE DC CONVERTERS OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT, OFFSHORE SYNCHRONOUS GENERATING UNITS IN A LARGE POWER STATION, OFFSHORE POWER PARK MODULES IN A LARGE POWER STATION AND OFFSHORE DC CONVERTERS IN A LARGE POWER STATION WHICH SELECT TO MEET THE FAULT RIDE THROUGH REQUIREMENTS AT THE INTERFACE POINT

CC.A.4A.1 Scope

The fault ride through requirement is defined in CC.6.3.15.1 (a), (b) and CC.6.3.15.3. This Appendix provides illustrations by way of examples only of CC.6.3.15.1 (a) (i) and further background and illustrations to CC.6.3.15.1 (1b) (i) and CC.6.3.15.1 (2b) (i) and is not intended to show all possible permutations.

CC.A.4A.2 Short Circuit Faults At Supergrid Voltage On The Onshore Transmission System Up To 140ms In Duration

For short circuit faults at Supergrid Voltage on the Onshore Transmission System (which could be at an Interface Point) up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15.1 (a) (i). Figures CC.A.4A.1 (a) and (b) illustrate two typical examples of voltage recovery for short-circuit faults cleared within 140ms by two circuit breakers (a) and three circuit breakers (b) respectively.

Figure CC.A.4A.1 (a)
Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

Requirements applicable to Synchronous Generating Units subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

For balanced Supergrid Voltage dips on the Onshore Transmission System having durations greater than 140ms and up to 3 minutes, the fault ride through requirement is defined in CC.6.3.15.1 (1b) and Figure 5a which is reproduced in this Appendix as Figure CC.A.4A3.1 and termed the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at a point on the Onshore Transmission System (or User System if located Onshore) to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected Synchronous Generating Units must withstand or ride through.

Figures CC.A.4A3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
CC.A.4A3.2  Requirements applicable to Power Park Modules or OTSDUW Plant and Apparatus subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

For balanced Supergrid Voltage dips on the Onshore Transmission System (which could be at an Interface Point) having durations greater than 140ms and up to 3 minutes the fault ride through requirement is defined in CC.6.3.15.1 (2b) and Figure 5b which is reproduced in this Appendix as Figure CC.A.4A3.3 and termed the voltage–duration profile.
This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at a point on the Onshore Transmission System (or User System if located Onshore) to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected Power Park Modules or OTSDUW Plant and Apparatus must withstand or ride through.

Figures CC.A.4A.4 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
50% retained voltage, 710 ms duration

Figure CC.A.4A3.4 (b)

85% retained voltage, 3 minutes duration

Figure CC.A.4A3.4 (c)
APPENDIX 4B - FAULT RIDE THROUGH REQUIREMENTS FOR OFFSHORE GENERATING UNITS IN A LARGE POWER STATION, OFFSHORE POWER PARK MODULES IN A LARGE POWER STATION AND OFFSHORE DC CONVERTERS IN A LARGE POWER STATION WHICH SELECT TO MEET THE FAULT RIDE THROUGH REQUIREMENTS AT THE LV SIDE OF THE OFFSHORE PLATFORM AS SPECIFIED IN CC.6.3.15.2

CC.A.4B.1 Scope
The fault ride through requirement is defined in CC.6.3.15.2 (a), (b) and CC.6.3.15.3. This Appendix provides illustrations by way of examples only of CC.6.3.15.2 (a) (i) and further background and illustrations to CC.6.3.15.2 (1b) and CC.6.3.15.2 (2b) and is not intended to show all possible permutations.

CC.A.4B.2 Voltage Dips On The LV Side Of The Offshore Platform Up To 140ms In Duration
For voltage dips on the LV Side of the Offshore Platform which last up to 140ms in duration, the fault ride through requirement is defined in CC.6.3.15.2 (a) (i). This includes Figure 6 which is reproduced here in Figure CC.A.4B.1. The purpose of this requirement is to translate the conditions caused by a balanced or unbalanced fault which occurs on the Onshore Transmission System (which may include the Interface Point) at the LV Side of the Offshore Platform.

![Graph showing voltage dip recovery](image)

V/Vn is the ratio of the voltage at the LV side of the Offshore Platform to the nominal voltage of the LV side of the Offshore Platform.

Figure CC.A.4B.1

Figures CC.A.4B.2 (a) and CC.A.4B.2 (b) illustrate two typical examples of the voltage recovery seen at the LV Side of the Offshore Platform for a short circuit fault cleared within 140ms by (a) two circuit breakers and (b) three circuit breakers on the Onshore Transmission System.
CCA.4B.3  **Voltage Dips Which Occur On The LV Side Of The Offshore Platform Greater Than 140ms In Duration**

CC.A.4B.3.1  Requirements applicable to Offshore Synchronous Generating Units subject to voltage dips which occur on the LV Side of the Offshore Platform greater than 140ms in duration.

In addition to CC.A.4B.2 the fault ride through requirements applicable to Offshore Synchronous Generating Units during balanced voltage dips which occur at the LV Side of the Offshore Platform and having durations greater than 140ms and up to 3 minutes are defined in CC.6.3.15.2 (1b) and Figure 7a which is reproduced in this Appendix as Figure CC.A.4B.3.1 and termed the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at the LV Side of the Offshore Platform to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected Offshore Synchronous Generating Units must withstand or ride through.
Figures CC.A.4B3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
Figure CC.A.4B3.2 (b)

50% retained voltage, 450ms duration

Figure CC.A.4B3.2 (c)

85% retained voltage, 180s duration

CC.A.4B.3.2 Requirements applicable to Offshore Power Park Modules subject to Voltage which occur on The LV Side Of The Offshore Platform greater than 140ms in duration.

In addition to CCA.4B.2 the fault ride through requirements applicable for Offshore Power Park Modules during balanced voltage dips which occur at the LV Side of the Offshore Platform and have durations greater than 140ms and up to 3 minutes are defined in CC.6.3.15.2 (2b) (i) and Figure 7b which is reproduced in this Appendix as Figure CC.A.4B.4 and termed the voltage–duration profile.
This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at the **LV Side of the Offshore Platform** to a disturbance. Rather, each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which connected **Offshore Power Park Modules** must withstand or ride through.

Figures CC.A.4B.5 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.
Figure CC.A.4B.5(b)

50% retained voltage, 710 ms duration

Figure CC.A.4B.5(c)

85% retained voltage, 3 minutes duration
APPENDIX 5 - TECHNICAL REQUIREMENTS
LOW FREQUENCY RELAYS FOR THE AUTOMATIC DISCONNECTION OF SUPPLIES AT LOW FREQUENCY

CC.A.5.1 Low Frequency Relays

CC.A.5.1.1 The Low Frequency Relays to be used shall have a setting range of 47.0 to 50Hz and be suitable for operation from a nominal AC input of 63.5, 110 or 240V. The following general parameters specify the requirements of approved Low Frequency Relays for automatic installations installed and commissioned after 1st April 2007 and provide an indication, without prejudice to the provisions that may be included in a Bilateral Agreement, for those installed and commissioned before 1st April 2007:

(a) Frequency settings: 47-50Hz in steps of 0.05Hz or better, preferably 0.01Hz;
(b) Operating time: Relay operating time shall not be more than 150 ms;
(c) Voltage lock-out: Selectable within a range of 55 to 90% of nominal voltage;
(d) Facility stages: One or two stages of Frequency operation;
(e) Output contacts: Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations:
(f) Accuracy: 0.01 Hz maximum error under reference environmental and system voltage conditions.
0.05 Hz maximum error at 8% of total harmonic distortion Electromagnetic Compatibility Level.

CC.A.5.2 Low Frequency Relay Voltage Supplies

CC.A.5.2.1 It is essential that the voltage supply to the Low Frequency Relays shall be derived from the primary System at the supply point concerned so that the Frequency of the Low Frequency Relays input voltage is the same as that of the primary System. This requires either:

(a) the use of a secure supply obtained from voltage transformers directly associated with the grid transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or

(b) the use of the substation 240V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the supply point concerned and is never derived from a standby supply Generating Unit or from another part of the User System.

CC.A.5.3 Scheme Requirements

CC.A.5.3.1 The tripping facility should be engineered in accordance with the following reliability considerations:

(a) Dependability

Failure to trip at any one particular Demand shedding point would not harm the overall operation of the scheme. However, many failures would have the effect of reducing the amount of Demand under low Frequency control. An overall reasonable minimum requirement for the dependability of the Demand shedding scheme is 96%, i.e. the average probability of failure of each Demand shedding point should be less than 4%. Thus the Demand under low Frequency control will not be reduced by more than 4% due to relay failure.

(b) Outages

Low Frequency Demand shedding schemes will be engineered such that the amount of Demand under control is as specified in Table CC.A.5.5.1a and is not reduced unacceptably during equipment outage or maintenance conditions.
The total operating time of the scheme, including circuit breakers operating time, shall where reasonably practicable, be less than 200ms. For the avoidance of doubt, the replacement of plant installed prior to October 2009 will not be required in order to achieve lower total scheme operating times.

CC.A.5.4 Low Frequency Relay Testing

CC.A.5.4.1 Low Frequency Relays installed and commissioned after 1st January 2007 shall be type tested in accordance with and comply with the functional test requirements for Frequency Protection contained in Energy Networks Association Technical Specification 48-6-5 Issue 1 dated 2005 “ENA Protection Assessment Functional Test Requirements – Voltage and Frequency Protection”.

For the avoidance of doubt, Low Frequency Relays installed and commissioned before 1st January 2007 shall comply with the version of CC.A.5.1.1 applicable at the time such Low Frequency Relays were commissioned.

CC.A.5.4.2 Each Non-Embedded Customer shall aim to execute testing on its low frequency demand disconnection relays installed within its network and in service at least once every three years, although this may be extended to no more than every five years if considered to be required for operational purposes.

CC.A.5.4.3 Each Network Operator and Relevant Transmission Licensee shall aim to execute testing on its low frequency demand disconnection relays installed within its network and in service at least once every three years, although this may be extended to no more than every five years if considered to be required for operational purposes.

CC.A.5.5 Scheme Settings

CC.A.5.5.1 Table CC.A.5.5.1a shows, for each Transmission Area, the percentage of Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand that each Network Operator whose System is connected to the Onshore Transmission System within such Transmission Area shall disconnect by Low Frequency Relays at a range of frequencies. Where a Network Operator’s System is connected to the National Electricity Transmission System in more than one Transmission Area, the settings for the Transmission Area in which the majority of the Demand is connected shall apply.

<table>
<thead>
<tr>
<th>Frequency Hz</th>
<th>% Demand disconnection for each Network Operator in Transmission Area</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>NGET</td>
</tr>
<tr>
<td>48.8</td>
<td>5</td>
</tr>
<tr>
<td>48.75</td>
<td>5</td>
</tr>
<tr>
<td>48.7</td>
<td>10</td>
</tr>
<tr>
<td>48.6</td>
<td>7.5</td>
</tr>
<tr>
<td>48.5</td>
<td>7.5</td>
</tr>
<tr>
<td>48.4</td>
<td>7.5</td>
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<tr>
<td>48.2</td>
<td>7.5</td>
</tr>
<tr>
<td>48.0</td>
<td>5</td>
</tr>
<tr>
<td>47.8</td>
<td>5</td>
</tr>
<tr>
<td>Total % Demand</td>
<td>60</td>
</tr>
</tbody>
</table>

Table CC.A.5.5.1a
Note – the percentages in table CC.A.5.5.1a are cumulative such that, for example, should the frequency fall to 48.6 Hz in the **NGET Transmission Area**, 27.5% of the total **Demand** connected to the **National Electricity Transmission System** in the **NGET Transmission Area** shall be disconnected by the action of **Low Frequency Relays**.

The percentage **Demand** at each stage shall be allocated as far as reasonably practicable. The cumulative total percentage **Demand** is a minimum.
APPENDIX 6 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR ONSHORE SYNCHRONOUS GENERATING UNITS

CC.A.6.1 Scope

CC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for Onshore Synchronous Generating Units that must be complied with by the GB Code User. This Appendix does not limit any site specific requirements that may be included in a Bilateral Agreement where in The Company’s reasonable opinion these facilities are necessary for system reasons.

CC.A.6.1.2 Where the requirements may vary the likely range of variation is given in this Appendix. It may be necessary to specify values outside this range where The Company identifies a system need, and notwithstanding anything to the contrary The Company may specify in the Bilateral Agreement values outside of the ranges provided in this Appendix 6. The most common variations are in the on-load excitation ceiling voltage requirements and the response time required of the Exciter. Actual values will be included in the Bilateral Agreement.

CC.A.6.1.3 Should a GB Generator anticipate making a change to the excitation control system it shall notify The Company under the Planning Code (PC.A.1.2(b) and (c)) as soon as the GB Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

CC.A.6.2 Requirements

CC.A.6.2.1 The Excitation System of an Onshore Synchronous Generating Unit shall include an excitation source (Exciter), a Power System Stabiliser and a continuously acting Automatic Voltage Regulator (AVR) and shall meet the following functional specification.

CC.A.6.2.2 In respect of Onshore Synchronous Generating Units with a Completion Date on or after 1 January 2009, and Onshore Synchronous Generating Units with a Completion Date before 1 January 2009 subject to a Modification to the excitation control facilities where the Bilateral Agreement does not specify otherwise, the continuously acting automatic excitation control system shall include a Power System Stabiliser (PSS) as a means of supplementary control. The functional specification of the Power System Stabiliser is included in CC.A.6.2.5.

CC.A.6.2.3 Steady State Voltage Control

CC.A.6.2.3.1 An accurate steady state control of the Onshore Generating Unit pre-set terminal voltage is required. As a measure of the accuracy of the steady-state voltage control, the Automatic Voltage Regulator shall have static zero frequency gain, sufficient to limit the change in terminal voltage to a drop not exceeding 0.5% of rated terminal voltage, when the Onshore Generating Unit output is gradually changed from zero to rated MVA output at rated voltage, Active Power and Frequency.

CC.A.6.2.4 Transient Voltage Control

CC.A.6.2.4.1 For a step change from 90% to 100% of the nominal Onshore Generating Unit terminal voltage, with the Onshore Generating Unit on open circuit, the Excitation System response shall have a damped oscillatory characteristic. For this characteristic, the time for the Onshore Generating Unit terminal voltage to first reach 100% shall be less than 0.6 seconds. Also, the time to settle within 5% of the voltage change shall be less than 3 seconds.

CC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the Onshore Generating Unit is subjected to a large voltage disturbance, the Exciter whose output is varied by the Automatic Voltage Regulator shall be capable of providing its achievable upper and lower limit ceiling voltages to the Onshore Generating Unit field in a time not exceeding that specified in the Bilateral Agreement. This will normally be not less than 50ms and not greater than 300ms. The achievable upper and lower limit ceiling voltages may be dependent on the voltage disturbance.
CC.A.6.2.4.3 The **Exciter** shall be capable of attaining an **Excitation System On Load Positive Ceiling Voltage** of not less than a value specified in the **Bilateral Agreement** that will be:

- not less than 2 per unit (pu)
- normally not greater than 3 pu
- exceptionally up to 4 pu

of **Rated Field Voltage** when responding to a sudden drop in voltage of 10 percent or more at the **Onshore Generating Unit** terminals. **The Company** may specify a value outside the above limits where **The Company** identifies a **System** need.

CC.A.6.2.4.4 If a static type **Exciter** is employed:

(i) the **field voltage** should be capable of attaining a negative ceiling level specified in the **Bilateral Agreement** after the removal of the step disturbance of CC.A.6.2.4.3. The specified value will be 80% of the value specified in CC.A.6.2.4.3. **The Company** may specify a value outside the above limits where **The Company** identifies a system need.

(ii) the **Exciter** must be capable of maintaining free firing when the **Onshore Generating Unit** terminal voltage is depressed to a level which may be between 20% to 30% of rated terminal voltage

(iii) the **Exciter** shall be capable of attaining a positive ceiling voltage not less than 80% of the **Excitation System On Load Positive Ceiling Voltage** upon recovery of the **Onshore Generating Unit** terminal voltage to 80% of rated terminal voltage following fault clearance. **The Company** may specify a value outside the above limits where **The Company** identifies a system need.

(iv) The requirement to provide a separate power source for the **Exciter** will be specified in the **Bilateral Agreement** if **The Company**, in coordination with the **Relevant Transmission Licensee**, identifies a **Transmission System** need.

CC.A.6.2.5 **Power Oscillations Damping Control**

CC.A.6.2.5.1 To allow the **Onshore Generating Unit** to maintain second and subsequent swing stability and also to ensure an adequate level of low frequency electrical damping power, the **Automatic Voltage Regulator** shall include a **Power System Stabiliser** as a means of supplementary control.

CC.A.6.2.5.2 Whatever supplementary control signal is employed, it shall be of the type which operates into the **Automatic Voltage Regulator** to cause the field voltage to act in a manner which results in the damping power being improved while maintaining adequate synchronising power.

CC.A.6.2.5.3 The arrangements for the supplementary control signal shall ensure that the **Power System Stabiliser** output signal relates only to changes in the supplementary control signal and not the steady state level of the signal. For example, if generator electrical power output is chosen as a supplementary control signal then the **Power System Stabiliser** output should relate only to changes in generator electrical power output and not the steady state level of power output. Additionally the **Power System Stabiliser** should not react to mechanical power changes in isolation for example during rapid changes in steady state load or when providing frequency response.

CC.A.6.2.5.4 The output signal from the **Power System Stabiliser** shall be limited to not more than ±10% of the **Onshore Generating Unit** terminal voltage signal at the **Automatic Voltage Regulator** input. The gain of the **Power System Stabiliser** shall be such that an increase in the gain by a factor of 3 shall not cause instability.

CC.A.6.2.5.5 The **Power System Stabiliser** shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application.
CC.A.6.2.5.6 The GB Generator will agree Power System Stabiliser settings with The Company, in coordination with the Relevant Transmission Licensee prior to the on-load commissioning detailed in BC2.11.2(d). To allow assessment of the performance before on-load commissioning the GB Generator will provide to The Company a report covering the areas specified in CP.A.3.2.1.

CC.A.6.2.5.7 The Power System Stabiliser must be active within the Excitation System at all times when Synchronised including when the Under Excitation Limiter or Over Excitation Limiter are active. When operating at low load when Synchronising or De-Synchronising an Onshore Generating Unit, the Power System Stabiliser may be out of service.

CC.A.6.2.5.8 Where a Power System Stabiliser is fitted to a Pumped Storage Unit it must function when the Pumped Storage Unit is in both generating and pumping modes.

CC.A.6.2.6 Overall Excitation System Control Characteristics

CC.A.6.2.6.1 The overall Excitation System shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5 Hz will be judged to be acceptable for this application.

CC.A.6.2.6.2 The response of the Automatic Voltage Regulator combined with the Power System Stabiliser shall be demonstrated by injecting similar step signal disturbances into the Automatic Voltage Regulator reference as detailed in OC5.A.2.2 and OC5.A.2.4. The Automatic Voltage Regulator shall include a facility to allow step injections into the Automatic Voltage Regulator voltage reference, with the Onshore Generating Unit operating at points specified by The Company (up to rated MVA output). The damping shall be judged to be adequate if the corresponding Active Power response to the disturbances decays within two cycles of oscillation.

CC.A.6.2.6.3 A facility to inject a band limited random noise signal into the Automatic Voltage Regulator voltage reference shall be provided for demonstrating the frequency domain response of the Power System Stabiliser. The tuning of the Power System Stabiliser shall be judged to be adequate if the corresponding Active Power response shows improved damping with the Power System Stabiliser in combination with the Automatic Voltage Regulator compared with the Automatic Voltage Regulator alone over the frequency range 0.3Hz – 2Hz.

CC.A.6.2.7 Under-Excitation Limiters

CC.A.6.2.7.1 The security of the power system shall also be safeguarded by means of MVAR Under Excitation Limiters fitted to the generator Excitation System. The Under Excitation Limiter shall prevent the Automatic Voltage Regulator reducing the generator excitation to a level which would endanger synchronous stability. The Under Excitation Limiter shall operate when the excitation system is providing automatic control. The Under Excitation Limiter shall respond to changes in the Active Power (MW) and the Reactive Power (MVAr), and to the square of the generator voltage in such a direction that an increase in voltage will permit an increase in leading MVAR. The characteristic of the Under Excitation Limiter shall be substantially linear from no-load to the maximum Active Power output of the Onshore Generating Unit at any setting and shall be readily adjustable.

CC.A.6.2.7.2 The performance of the Under Excitation Limiter shall be independent of the rate of change of the Onshore Generating Unit load and shall be demonstrated by testing as detailed in OC5.A.2.5. The resulting maximum overshoot in response to a step injection which operates the Under Excitation Limiter shall not exceed 4% of the Onshore Generating Unit rated MVA. The operating point of the Onshore Generating Unit shall be returned to a steady state value at the limit line and the final settling time shall not be greater than 5 seconds. When the step change in Automatic Voltage Regulator reference voltage is reversed, the field voltage should begin to respond without any delay and should not be held down by the Under Excitation Limiter. Operation into or out of the preset limit levels shall ensure that any resultant oscillations are damped so that the disturbance is within 0.5% of the Onshore Generating Unit MVA rating within a period of 5 seconds.
CC.A.6.2.7.3  The **GB Generator** shall also make provision to prevent the reduction of the **Onshore Generating Unit** excitation to a level which would endanger synchronous stability when the **Excitation System** is under manual control.

CC.A.6.2.8  **Over-Excitation Limiters**

CC.A.6.2.8.1  The settings of the **Over-Excitation Limiter**, where it exists, shall ensure that the **Generating Unit's excitation** is not limited to less than the maximum value that can be achieved whilst ensuring the **Onshore Generating Unit** is operating within its design limits. If the **Generating Unit's excitation** is reduced following a period of operation at a high level, the rate of reduction shall not exceed that required to remain within any time dependent operating characteristics of the **Onshore Generating Unit**.

CC.A.6.2.8.2  The performance of the **Over-Excitation Limiter**, where it exists, shall be demonstrated by testing as described in OC5.A.2.6. Any operation beyond the **Over-Excitation Limit** shall be controlled by the **Over-Excitation Limiter** without the operation of any **Protection** that could trip the **Onshore Generating Unit**.

CC.A.6.2.8.3  The **GB Generator** shall also make provision to prevent any over-excitation restriction of the generator when the **Excitation System** is under manual control, other than that necessary to ensure the **Onshore Generating Unit** is operating within its design limits.
APPENDIX 7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR ONSHORE NON-SYNCHRONOUS GENERATING UNITS, ONSHORE DC CONVERTERS, ONSHORE POWER PARK MODULES AND OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT

CC.A.7.1 Scope

CC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for Onshore Non-Synchronous Generating Units, Onshore DC Converters, Onshore Power Park Modules and OTSDUW Plant and Apparatus at the Interface Point that must be complied with by the GB Code User. This Appendix does not limit any site specific requirements that may be included in a Bilateral Agreement where in The Company’s reasonable opinion these facilities are necessary for system reasons.

CC.A.7.1.2 Proposals by GB Generators to make a change to the voltage control systems are required to be notified to The Company under the Planning Code (PC.A.1.2(b) and (c)) as soon as the GB Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

CC.A.7.2 Requirements

CC.A.7.2.1 The Company requires that the continuously acting automatic voltage control system for the Onshore Non-Synchronous Generating Unit, Onshore DC Converter or Onshore Power Park Module or OTSDUW Plant and Apparatus shall meet the following functional performance specification. If a Network Operator has confirmed to The Company that its network to which an Embedded Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus is connected is restricted such that the full reactive range under the steady state voltage control requirements (CC.A.7.2.2) cannot be utilised, The Company may specify in the Bilateral Agreement alternative limits to the steady state voltage control range that reflect these restrictions. Where the Network Operator subsequently notifies The Company that such restriction has been removed, The Company may propose a Modification to the Bilateral Agreement (in accordance with the CUSC contract) to remove the alternative limits such that the continuously acting automatic voltage control system meets the following functional performance specification. All other requirements of the voltage control system will remain as in this Appendix.

CC.A.7.2.2 Steady State Voltage Control

CC.A.7.2.2.1 The Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module or OTSDUW Plant and Apparatus shall provide continuous steady state control of the voltage at the Onshore Grid Entry Point (or Onshore User System Entry Point if Embedded) (or the Interface Point in the case of OTSDUW Plant and Apparatus) with a Setpoint Voltage and Slope characteristic as illustrated in Figure CC.A.7.2.2a. It should be noted that where the Reactive Power capability requirement of a directly connected Onshore Non-Synchronous Generating Unit, Onshore DC Converter, Onshore Power Park Module in Scotland, or OTSDUW Plant and Apparatus in Scotland as specified in CC.6.3.2 (c), is not at the Onshore Grid Entry Point or Interface Point, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer.
CC.A.7.2.2.2 The continuously acting automatic control system shall be capable of operating to a Setpoint Voltage between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt, values of 95%, 95.25%, 95.5% … may be specified, but not intermediate values. The initial Setpoint Voltage will be 100%. The tolerance within which this Setpoint Voltage shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. The Company may request the GB Generator to implement an alternative Setpoint Voltage within the range of 95% to 105%. For Embedded GB Generators the Setpoint Voltage will be discussed between The Company and the relevant Network Operator and will be specified to ensure consistency with CC.6.3.4.

CC.A.7.2.2.3 The Slope characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial Slope setting will be 4%. The tolerance within which this Slope shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a Slope setting of 4%, the achieved value shall be between 3.5% and 4.5%. The Company may request the GB Generator to implement an alternative slope setting within the range of 2% to 7%. For Embedded GB Generators the Slope setting will be discussed between The Company and the relevant Network Operator and will be specified to ensure consistency with CC.6.3.4.
Figure CC.A.7.2.2b

Onshore Grid Entry Point voltage
(or Onshore User System Entry Point voltage if Embedded)
Connections at 33kV and below

Figure CC.A.7.2.2c
Figure CC.A.7.2.2b shows the required envelope of operation for Onshore Non-Synchronous Generating Units, Onshore DC Converters, OTSDUW Plant and Apparatus and Onshore Power Park Modules except for those Embedded at 33kV and below or directly connected to the National Electricity Transmission System at 33kV and below. Figure CC.A.7.2.2c shows the required envelope of operation for Onshore Non-Synchronous Generating Units, Onshore DC Converters and Onshore Power Park Modules Embedded at 33kV and below or directly connected to the National Electricity Transmission System at 33kV and below. Where the Reactive Power capability requirement of a directly connected Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module in Scotland, as specified in CC.6.3.2 (c), is not at the Onshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus, the values of Qmin and Qmax shown in this figure will be as modified by the 33/132kV or 33/275kV or 33/400kV transformer. The enclosed area within points ABCDEFGH is the required capability range within which the Slope and Setpoint Voltage can be changed.

Should the operating point of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module deviate so that it is no longer a point on the operating characteristic (figure CC.A.7.2.2a) defined by the target Setpoint Voltage and Slope, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum lagging limit at an Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) above 95%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum lagging Reactive Power output for voltage reductions down to 95%. This requirement is indicated by the line EF in figures CC.A.7.2.2b and CC.A.7.2.2c. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum leading limit at an Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) below 105%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum leading Reactive Power output for voltage increases up to 105%. This requirement is indicated by the line AB in figures CC.A.7.2.2b and CC.A.7.2.2c.
CC.A.7.2.2.7 For Onshore Grid Entry Point voltages (or Onshore User System Entry Point voltages) below 95%, the lagging Reactive Power capability of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures CC.A.7.2.2b and CC.A.7.2.2c. For Onshore Grid Entry Point voltages (or Onshore User System Entry Point voltages if Embedded or Interface Point voltages) above 105%, the leading Reactive Power capability of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures CC.A.7.2.2b and CC.A.7.2.2c. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum lagging limit at an Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) below 95%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter or Onshore Power Park Module shall maintain maximum lagging reactive current output for further voltage decreases. Should the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module reach its maximum leading limit at a Onshore Grid Entry Point voltage (or User System Entry Point voltage if Embedded or Interface Point voltage in the case of an OTSDUW Plant and Apparatus) above 105%, the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall maintain maximum leading reactive current output for further voltage increases.

CC.A.7.2.2.8 All OTSDUW Plant and Apparatus must be capable of enabling GB Code Users undertaking OTSDUW to comply with an instruction received from The Company relating to a variation of the Setpoint Voltage at the Interface Point within 2 minutes of such instruction being received.

CC.A.7.2.2.9 For OTSDUW Plant and Apparatus connected to a Network Operator’s System where the Network Operator has confirmed to The Company that its System is restricted in accordance with CC.A.7.2.1, clause CC.A.7.2.2.8 will not apply unless The Company can reasonably demonstrate that the magnitude of the available change in Reactive Power has a significant effect on voltage levels on the Onshore National Electricity Transmission System.

CC.A.7.2.3 Transient Voltage Control

CC.A.7.2.3.1 For an on-load step change in Onshore Grid Entry Point or Onshore User System Entry Point voltage, or in the case of OTSDUW Plant and Apparatus an on-load step change in Transmission Interface Point voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the Reactive Power output response of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAr seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure CC.A.7.2.3.1a.

(ii) the response shall be such that 90% of the change in the Reactive Power output of the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module, will be achieved within

- 1 second, where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value, as required by CC.6.3.2 (or, if appropriate, CC.A.7.2.2.6 or CC.A.7.2.2.7); and
2 seconds, for **Plant and Apparatus** installed on or after 1 December 2017, where the step is sufficiently large to require a change in the steady state **Reactive Power** output from its maximum leading value to its maximum lagging value or vice versa.

(iii) the magnitude of the **Reactive Power** output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within 2 seconds from achieving 90% of the response as defined in CC.A.7.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state **Reactive Power**.

(v) following the transient response, the conditions of CC.A.7.2.2 apply.

![Diagram showing MVAr response over time](image)

**CC.A.7.2.3.2** An **Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus** or **Onshore Power Park Module** installed on or after 1 December 2017 shall be capable of:

(a) changing its **Reactive Power** output from its maximum lagging value to its maximum leading value, or vice versa, then reverting back to the initial level of **Reactive Power** output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing its **Reactive Power** output from zero to its maximum leading value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero **Reactive Power** output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to **The Company** in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to CC.A.7.2.3.1 where the change in **Reactive Power** output is in response to an on-load step change in **Onshore Grid Entry Point** or **Onshore User System Entry Point** voltage, or in the case of **OTSDUW Plant and Apparatus** an on-load step change in **Transmission Interface Point** voltage.

**CC.A.7.2.4** **Power Oscillation Damping**
CC.A.7.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a Power System Stabiliser (PSS) shall be specified in the Bilateral Agreement if, in The Company’s view, this is required for system reasons. However if a Power System Stabiliser is included in the voltage control system its settings and performance shall be agreed with The Company and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the GB Generator will provide to The Company a report covering the areas specified in CP.A.3.2.2.

CC.A.7.2.5 Overall Voltage Control System Characteristics

CC.A.7.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point voltage in the case of OTSDUW Plant and Apparatus).

CC.A.7.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the Onshore Non-Synchronous Generating Unit, Onshore DC Converter, OTSDUW Plant and Apparatus or Onshore Power Park Module should also meet this requirement.

CC.A.7.2.5.3 The response of the voltage control system (including the Power System Stabiliser if employed) shall be demonstrated by testing in accordance with OC5A.A.3.

< END OF CONNECTION CONDITIONS >
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ECC.1 INTRODUCTION

ECC.1.1 The European Connection Conditions ("ECC") specify both:

(a) the minimum technical, design and operational criteria which must be complied with by:

(i) any EU Code User connected to or seeking connection with the National Electricity Transmission System, or

(ii) EU Generators or HVDC System Owners connected to or seeking connection to a User's System which is located in Great Britain or Offshore, or

(iii) Network Operators who are EU Code Users

(iv) Network Operators who are GB Code Users but only in respect of:-

(a) Their obligations in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement for whom the requirements of ECC.3.1(b)(iii) apply alone; and/or

(b) The requirements of this ECC only in relation to each EU Grid Supply Point. Network Operators in respect of all other Grid Supply Points should continue to satisfy the requirements as specified in the CCs.

(v) Non-Embedded Customers who are EU Code Users

(b) the minimum technical, design and operational criteria with which The Company will comply in relation to the part of the National Electricity Transmission System at the Connection Site with Users. In the case of any OTSDUW Plant and Apparatus, the ECC also specify the minimum technical, design and operational criteria which must be complied with by the User when undertaking OTSDUW.

(c) The requirements of Retained EU Law (Commission Regulation (EU) 2016/631) shall not apply to

(i) Power Generating Modules that are installed to provide backup power and operate in parallel with the Total System for less than 5 minutes per calendar month while the System is in normal state. Parallel operation during maintenance or commissioning of tests of that Power Generating Module shall not count towards that five minute limit.

(ii) Power Generating Modules connected to the Transmission System or Network Operators System which are not operated in synchronism with a Synchronous Area.

(iii) Power Generating Modules that do not have a permanent Connection Point or User System Entry Point and used by The Company to temporarily provide power when normal System capacity is partly or completely unavailable.

(iv) Electricity Storage Modules.

(d) Storage Users are required to comply with the entirety of the ECC but are not subject to the requirements of Retained EU Law (Commission Regulation (EU) 2016/631, Commission Regulation (EU) 2016/1388 and Commission Regulation (EU) 2016/1485). The requirements of the ECC shall therefore be enforceable against Storage Users under the Grid Code only (and not under any of the aforementioned Retained EU Law) and any derogation sought by a Storage User in respect of the ECC shall be deemed a derogation from the Grid Code only (and not from the aforementioned Retained EU Law).
ECC.2 OBJECTIVE

ECC.2.1 The objective of the ECC is to ensure that by specifying minimum technical, design and operational criteria the basic rules for connection to the National Electricity Transmission System and (for certain Users) to a User’s System are similar for all Users of an equivalent category and will enable The Company to comply with its statutory and Transmission Licence obligations and the applicable Retained EU Law.

ECC.2.2 In the case of any OTSDUW the objective of the ECC is to ensure that by specifying the minimum technical, design and operational criteria the basic rules relating to an Offshore Transmission System designed and constructed by an Offshore Transmission Licensee and designed and/or constructed by a User under the OTSDUW Arrangements are equivalent.

ECC.2.3 Provisions of the ECC which apply in relation to OTSDUW and OTSUA, and/or a Transmission Interface Site, shall (in any particular case) apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply, without prejudice to the continuing application of provisions of the ECC applying in relation to the relevant Offshore Transmission System and/or Connection Site. It is the case therefore that in cases where the OTSUA becomes operational prior to the OTSUA Transfer Time that a EU Generator is required to comply with this ECC both as it applies to its Plant and Apparatus at a Connection Site/Connection Point and the OTSUA at the Transmission Interface Site/Transmission Interface Point until the OTSUA Transfer Time and this ECC shall be construed accordingly.

ECC.2.4 In relation to OTSDUW, provisions otherwise to be contained in a Bilateral Agreement may be contained in the Construction Agreement, and accordingly a reference in the ECC to a relevant Bilateral Agreement includes the relevant Construction Agreement.

ECC.3 SCOPE

ECC.3.1 The ECC applies to The Company and to Users, which in the ECC means:

(a) EU Generators (other than those which only have Embedded Small Power Stations), including those undertaking OTSDUW including Power Generating Modules, and DC Connected Power Park Modules. For the avoidance of doubt, Electricity Storage Modules are included within the definition of Power Generating Modules for which the requirements of the ECC would be equally applicable.

(b) Network Operators but only in respect of:-

(i) Network Operators who are EU Code Users

(ii) Network Operators who only have EU Grid Supply Points

(iii) Embedded Medium Power Stations not subject to a Bilateral Agreement as provided for in ECC.3.2, ECC.3.3, EC3.4, EC3.5, ECC.6.4.4 and ECA.3.4;

(iv) Notwithstanding the requirements of ECC3.1(b)(i)(ii) and (iii), Network Operators who own and/or operate EU Grid Supply Points, are only required to satisfy the requirements of this ECC in relation to each EU Grid Supply Point. Network Operators in respect of all other Grid Supply Points should continue to satisfy the requirements as specified in the CCs.

(c) Non-Embedded Customers who are also EU Code Users;

(d) HVDC System Owners who are also EU Code Users; and

(e) BM Participants and Externally Interconnected System Operators who are also EU Code Users in respect of ECC.6.5 only.
The above categories of User will become bound by the applicable sections of the ECC prior to them generating, distributing, storing, supplying or consuming, as the case may be, and references to the various categories should, therefore, be taken as referring to them in that prospective role.

Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement Provisions.

The following provisions apply in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement.

The obligations within the ECC that are expressed to be applicable to EU Generators in respect of Embedded Medium Power Stations not subject to a Bilateral Agreement and HVDC System Owners in respect of Embedded HVDC Systems not subject to a Bilateral Agreement (where the obligations are in each case listed in ECC.3.3.2) shall be read and construed as obligations that the Network Operator within whose System any such Medium Power Station or HVDC System is Embedded must ensure are performed and discharged by the EU Generator or the HVDC Owner. Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement which are located Offshore and which are connected to an Onshore User System will be required to meet the applicable requirements of the Grid Code as though they are an Onshore Generator or Onshore HVDC System Owner connected to an Onshore User System Entry Point.

The Network Operator within whose System a Medium Power Station not subject to a Bilateral Agreement is Embedded or a HVDC System not subject to a Bilateral Agreement is Embedded must ensure that the following obligations in the ECC are performed and discharged by the EU Generator in respect of each such Embedded Medium Power Station or the HVDC System Owner in the case of an Embedded HVDC System:

- ECC.5.1
- ECC.5.2.2
- ECC.5.3
- ECC.6.1.3
- ECC.6.1.5 (b)
- ECC.6.3.2, ECC.6.3.3, ECC.6.3.4, ECC.6.3.6, ECC.6.3.7, ECC.6.3.8, ECC.6.3.9, ECC.6.3.10, ECC.6.3.12, ECC.6.3.13, ECC.6.3.15, ECC.6.3.16
- ECC.6.4.4
- ECC.6.5.6 (where required by ECC.6.4.4)

In respect of ECC.6.2.2.2, ECC.6.2.2.3, ECC.6.2.2.5, ECC.6.1.5(a), ECC.6.1.5(b) and ECC.6.3.11 equivalent provisions as co-ordinated and agreed with the Network Operator and EU Generator or HVDC System Owner may be required. Details of any such requirements will be notified to the Network Operator in accordance with ECC.3.5.

In the case of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement the requirements in:

- ECC.6.1.6
- ECC.6.3.8
- ECC.6.3.12
- ECC.6.3.15
ECC.6.3.16
ECC.6.3.17

that would otherwise have been specified in a Bilateral Agreement will be notified to the relevant Network Operator in writing in accordance with the provisions of the CUSC and the Network Operator must ensure such requirements are performed and discharged by the Generator or the HVDC System owner.

ECC.3.4

In the case of Offshore Embedded Power Generating Modules connected to an Offshore User's System which directly connects to an Offshore Transmission System, any additional requirements in respect of such Offshore Embedded Power Generating Modules may be specified in the relevant Bilateral Agreement with the Network Operator or in any Bilateral Agreement between The Company and such Offshore Generator.

ECC.3.5

In the case of a Generator undertaking OTSDUW connecting to an Onshore Network Operator's System, any additional requirements in respect of such OTSDUW Plant and Apparatus will be specified in the relevant Bilateral Agreement with the EU Generator. For the avoidance of doubt, requirements applicable to EU Generators undertaking OTSDUW and connecting to a Network Operator's User System, shall be consistent with those applicable requirements of Generators undertaking OTSDUW and connecting to a Transmission Interface Point.

ECC.3.6

The requirements of this ECC shall apply to EU Code Users in respect of Power Generating Modules (including DC Connected Power Park Modules and Electricity Storage Modules) and HVDC Systems.

ECC.4

PROCEDURE

ECC.4.1

The CUSC contains certain provisions relating to the procedure for connection to the National Electricity Transmission System or, in the case of Embedded Power Stations or Embedded HVDC Systems, becoming operational and includes provisions relating to certain conditions to be complied with by EU Code Users prior to and during the course of The Company notifying the User that it has the right to become operational. The procedure for an EU Code User to become connected is set out in the Compliance Processes.

ECC.5

CONNECTION

ECC.5.1

The provisions relating to connecting to the National Electricity Transmission System (or to a User's System in the case of a connection of an Embedded Large Power Station or Embedded Medium Power Stations or Embedded HVDC System) are contained in:

(a) the CUSC and/or CUSC Contract (or in the relevant application form or offer for a CUSC Contract);

(b) or, in the case of an Embedded Development, the relevant Distribution Code and/or the Embedded Development Agreement for the connection (or in the relevant application form or offer for an Embedded Development Agreement),

and include provisions relating to both the submission of information and reports relating to compliance with the relevant European Connection Conditions for that EU Code User, Safety Rules, commissioning programmes, Operation Diagrams and approval to connect (and their equivalents in the case of Embedded Medium Power Stations not subject to a Bilateral Agreement or Embedded HVDC Systems not subject to a Bilateral Agreement). References in the ECC to the "Bilateral Agreement" and/or "Construction Agreement" and/or "Embedded Development Agreement" shall be deemed to include references to the application form or offer therefor.

ECC.5.2

Items For Submission
Prior to the Completion Date (or, where the EU Generator is undertaking OTSDUW, any later date specified) under the Bilateral Agreement and/or Construction Agreement, the following is submitted pursuant to the terms of the Bilateral Agreement and/or Construction Agreement:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in ECC.6;

(c) copies of all Safety Rules and Local Safety Instructions applicable at Users’ Sites which will be used at the Transmission/User interface (which, for the purpose of OC8, must be to The Company’s satisfaction regarding the procedures for Isolation and Earthing. The Company will consult the Relevant Transmission Licensee when determining whether the procedures for Isolation and Earthing are satisfactory);

(d) information to enable the preparation of the Site Responsibility Schedules on the basis of the provisions set out in Appendix 1;

(e) an Operation Diagram for all HV Apparatus on the User side of the Connection Point as described in ECC.7;

(f) the proposed name of the User Site (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

(g) written confirmation that Safety Co-ordinators acting on behalf of the User are authorised and competent pursuant to the requirements of OC8;

(h) Such RISSP prefixes pursuant to the requirements of OC8. Such RISSP prefixes shall be circulated utilising a proforma in accordance with OC8;

(i) a list of the telephone numbers for Joint System Incidents at which senior management representatives nominated for the purpose can be contacted and confirmation that they are fully authorised to make binding decisions on behalf of the User, pursuant to OC9;

(j) a list of managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User;

(k) information to enable the preparation of the Site Common Drawings as described in ECC.7;

(l) a list of the telephone numbers for the Users facsimile machines referred to in ECC.6.5.9; and

(m) for Sites in Scotland and Offshore a list of persons appointed by the User to undertake operational duties on the User’s System (including any OTSDUW prior to the OTSUA Transfer Time) and to issue and receive operational messages and instructions in relation to the User’s System (including any OTSDUW prior to the OTSUA Transfer Time); and an appointed person or persons responsible for the maintenance and testing of User’s Plant and Apparatus.

Prior to the Completion Date the following must be submitted to The Company by the Network Operator in respect of an Embedded Development:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in ECC.6;
(c) the proposed name of the Embedded Medium Power Station or Embedded HVDC System (which shall be agreed with The Company unless it is the same as, or confusingly similar to, the name of other Transmission Site or User Site);

ECC.5.2.3 Prior to the Completion Date contained within an Offshore Transmission Distribution Connection Agreement the following must be submitted to The Company by the Network Operator in respect of a proposed new Interface Point within its User System:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in ECC.6;

(c) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

ECC.5.2.4 In the case of OTSDUW Plant and Apparatus (in addition to items under ECC.5.2.1 in respect of the Connection Site), prior to the Completion Date (or any later date specified) under the Construction Agreement the following must be submitted to The Company by the User in respect of the proposed new Connection Point and Interface Point:

(a) updated Planning Code data (Standard Planning Data, Detailed Planning Data and OTSDUW Data and Information), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand, pursuant to the requirements of the Planning Code;

(b) details of the Protection arrangements and settings referred to in ECC.6;

(c) information to enable preparation of the Site Responsibility Schedules at the Transmission Interface Site on the basis of the provisions set out in Appendix E1.

(d) the proposed name of the Interface Point (which shall not be the same as, or confusingly similar to, the name of any Transmission Site or of any other User Site);

ECC.5.3 (a) Of the items ECC.5.2.1 (c), (e), (g), (h), (k) and (m) need not be supplied in respect of Embedded Power Stations or Embedded HVDC Systems,

(b) item ECC.5.2.1(i) need not be supplied in respect of Embedded Small Power Stations and Embedded Medium Power Stations or Embedded HVDC Systems with a Registered Capacity of less than 100MW, and

(c) items ECC.5.2.1(d) and (j) are only needed in the case where the Embedded Power Station or the Embedded HVDC System is within a Connection Site with another User.

ECC.6 TECHNICAL, DESIGN AND OPERATIONAL CRITERIA

ECC.6.1 National Electricity Transmission System Performance Characteristics

ECC.6.1.1 The Company shall ensure that, subject as provided in the Grid Code, the National Electricity Transmission System complies with the following technical, design and operational criteria in relation to the part of the National Electricity Transmission System at the Connection Site with a User and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point (unless otherwise specified in ECC.6) although in relation to operational criteria The Company may be unable (and will not be required) to comply with this obligation to the extent that there are insufficient Power Stations or User Systems are not available or Users do not comply with The Company's instructions or otherwise do not comply with the Grid Code and each User shall ensure that its Plant and Apparatus complies with the criteria set out in ECC.6.1.5.

ECC.6.1.2 Grid Frequency Variations
ECC.6.1.2.1 Grid Frequency Variations

ECC.6.1.2.1.1 The Frequency of the National Electricity Transmission System shall be nominally 50Hz and shall be controlled within the limits of 49.5 - 50.5Hz unless exceptional circumstances prevail.

ECC.6.1.2.1.2 The System Frequency could rise to 52Hz or fall to 47Hz in exceptional circumstances. Design of User’s Plant and Apparatus and OTSDUW Plant and Apparatus must enable operation of that Plant and Apparatus within that range in accordance with the following:

<table>
<thead>
<tr>
<th>Frequency Range</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>51.5Hz - 52Hz</td>
<td>Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5Hz.</td>
</tr>
<tr>
<td>51Hz - 51.5Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the Frequency is above 51Hz.</td>
</tr>
<tr>
<td>49.0Hz - 51Hz</td>
<td>Continuous operation is required</td>
</tr>
<tr>
<td>47.5Hz - 49.0Hz</td>
<td>Operation for a period of at least 90 minutes is required each time the Frequency is below 49.0Hz.</td>
</tr>
<tr>
<td>47Hz - 47.5Hz</td>
<td>Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5Hz.</td>
</tr>
</tbody>
</table>

ECC.6.1.2.1.3 For the avoidance of doubt, disconnection, by frequency or speed based relays is not permitted within the frequency range 47.5Hz to 51.5Hz. EU Generators should however be aware of the combined voltage and frequency operating ranges as defined in ECC.6.3.12 and ECC.6.3.13.

ECC.6.1.2.1.4 The Company in co-ordination with the Relevant Transmission Licensee and/or Network Operator and a User may agree on wider variations in frequency or longer minimum operating times to those set out in ECC.6.1.2.1.2 or specific requirements for combined frequency and voltage deviations. Any such requirements in relation to Power Generating Modules shall be in accordance with ECC.6.3.12 and ECC.6.3.13. A User shall not unreasonably withhold consent to apply wider frequency ranges or longer minimum times for operation taking account of their economic and technical feasibility.

ECC.6.1.2.2 Grid Frequency variations for HVDC Systems and Remote End HVDC Converter Stations

ECC.6.1.2.2.1 HVDC Systems and Remote End HVDC Converter Stations shall be capable of staying connected to the System and remaining operable within the frequency ranges and time periods specified in Table ECC.6.1.2.2 below. This requirement shall continue to apply during the Fault Ride Through conditions defined in ECC.6.3.15

<table>
<thead>
<tr>
<th>Frequency Range (Hz)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>47.0 – 47.5Hz</td>
<td>60 seconds</td>
</tr>
<tr>
<td>47.5 – 49.0Hz</td>
<td>90 minutes and 30 seconds</td>
</tr>
<tr>
<td>49.0 – 51.0Hz</td>
<td>Unlimited</td>
</tr>
<tr>
<td>51.0 – 51.5Hz</td>
<td>90 minutes and 30 seconds</td>
</tr>
<tr>
<td>51.5Hz – 52 Hz</td>
<td>20 minutes</td>
</tr>
</tbody>
</table>

Table ECC.6.1.2.2 – Minimum time periods HVDC Systems and Remote End HVDC Converter Stations shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the National Electricity Transmission System

ECC.6.1.2.2.2 The Company in coordination with the Relevant Transmission Licensee and a HVDC System Owner may agree wider frequency ranges or longer minimum operating times if required to preserve or restore system security. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the HVDC System Owner shall not unreasonably withhold consent.
ECC.6.1.2.2.3 Not withstanding the requirements of ECC.6.1.2.2.1, an HVDC System or Remote End HVDC Converter Station shall be capable of automatic disconnection at frequencies specified by The Company and/or Relevant Network Operator.

ECC.6.1.2.2.4 In the case of Remote End HVDC Converter Stations where the Remote End HVDC Converter Station is operating at either nominal frequency other than 50Hz or a variable frequency, the requirements defined in ECC6.1.2.2.1 to ECC.6.1.2.2.3 shall apply to the Remote End HVDC Converter Station other than in respect of the frequency ranges and time periods.

ECC.6.1.2.3 Grid Frequency Variations for DC Connected Power Park Modules

ECC.6.1.2.3.1 DC Connected Power Park Modules shall be capable of staying connected to the Remote End DC Converter network at the HVDC Interface Point and operating within the Frequency ranges and time periods specified in Table ECC.6.1.2.3 below. Where a nominal frequency other than 50Hz, or a Frequency variable by design is used as agreed with The Company and the Relevant Transmission Licensee the applicable Frequency ranges and time periods shall be specified in the Bilateral Agreement which shall (where applicable) reflect the requirements in Table ECC.6.1.2.3.

<table>
<thead>
<tr>
<th>Frequency Range (Hz)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>47.0 – 47.5Hz</td>
<td>20 seconds</td>
</tr>
<tr>
<td>47.5 – 49.0Hz</td>
<td>90 minutes</td>
</tr>
<tr>
<td>49.0 – 51.0Hz</td>
<td>Unlimited</td>
</tr>
<tr>
<td>51.0 – 51.5Hz</td>
<td>90 minutes</td>
</tr>
<tr>
<td>51.5Hz – 52 Hz</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

Table ECC.6.1.2.3 – Minimum time periods a DC Connected Power Park Module shall be able to operate for different frequencies deviating from a nominal value without disconnecting from the System

ECC.6.1.2.3.2 The Company in coordination with the Relevant Transmission Licensee and a Generator may agree wider frequency ranges or longer minimum operating times if required to preserve or restore system security and to ensure the optimum capability of the DC Connected Power Park Module. If wider frequency ranges or longer minimum times for operation are economically and technically feasible, the EU Generator shall not unreasonably withhold consent.

ECC.6.1.3 Not used

ECC.6.1.4 Grid Voltage Variations

ECC.6.1.4.1 Grid Voltage Variations for Users excluding DC Connected Power Park Modules and Remote End HVDC Converters
The voltage on part of the National Electricity Transmission System operating at nominal voltages of greater than 300kV at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point, excluding DC Connected Power Park Modules and Remote End HVDC Converters) will normally remain within ±5% of the nominal value unless abnormal conditions prevail. The minimum voltage is -10% and the maximum voltage is +10% unless abnormal conditions prevail, but voltages between +5% and +10% will not last longer than 15 minutes unless abnormal conditions prevail. For nominal voltages of 110kV and up to and including 300kV voltages on the parts of the National Electricity Transmission System at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point), excluding DC Connected Power Park Modules and Remote End HVDC Converters) will normally remain within the limits ±10% of the nominal value unless abnormal conditions prevail. At nominal System voltages below 110kV the voltage of the National Electricity Transmission System at each Connection Site with a User (and in the case of OTSDUW Plant and Apparatus, a Transmission Interface Point) will normally remain within the limits ±6% of the nominal value unless abnormal conditions prevail. Under fault conditions, the voltage may collapse transiently to zero at the point of fault until the fault is cleared. The normal operating ranges of the National Electricity Transmission System are summarised below:

<table>
<thead>
<tr>
<th>National Electricity Transmission System Nominal Voltage</th>
<th>Normal Operating Range</th>
<th>Time period for Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage (percentage of Nominal Voltage) Pu (1pu relates to the Nominal Voltage)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Greater than 300kV</td>
<td>V -10% to +5% 0.90pu- 1.05pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td></td>
<td>V +5% to +10% 1.05pu- 1.10pu</td>
<td>15 minutes</td>
</tr>
<tr>
<td>110kV up to 300kV</td>
<td>V ±10% 0.90- 1.10pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td>Below 110kV</td>
<td>±6% 0.94pu- 1.06pu</td>
<td>Unlimited</td>
</tr>
</tbody>
</table>

The Company and a User may agree greater variations or longer minimum time periods of operation in voltage to those set out above in relation to a particular Connection Site, and insofar as a greater variation is agreed, the relevant figure set out above shall, in relation to that User at the particular Connection Site, be replaced by the figure agreed.

ECC.6.1.4.2 Grid Voltage Variations for all DC Connected Power Park Modules

ECC.6.1.4.2.1 All DC Connected Power Park Modules shall be capable of staying connected to the Remote End HVDC Converter Station at the HVDC Interface Point and operating within the voltage ranges and time periods specified in Tables ECC.6.1.4.2(a) and ECC.6.1.4.2(b) below. The applicable voltage range and time periods specified are selected based on the reference 1pu voltage.

<table>
<thead>
<tr>
<th>Voltage Range (pu)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.85pu – 0.9pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td>0.9pu – 1.1pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td>1.1pu – 1.15pu</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

Table ECC.6.1.4.2(a) – Minimum time periods for which DC Connected Power Park Modules shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is 110kV or above and less than 300kV.
Table ECC.6.1.4.2(b) – Minimum time periods for which DC Connected Power Park Modules shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is from 300kV up to and including 400kV.

<table>
<thead>
<tr>
<th>Voltage Range (pu)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.85pu – 0.9pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td>0.9pu – 1.05pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td>1.05pu – 1.15pu</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

ECC.6.1.4.2.2 The Company and a EU Generator in respect of a DC Connected Power Park Module may agree greater voltage ranges or longer minimum operating times. If greater voltage ranges or longer minimum times for operation are economically and technically feasible, the EU Generator shall not unreasonably withhold any agreement.

ECC.6.1.4.2.3 For DC Connected Power Park Modules which have an HVDC Interface Point to the Remote End HVDC Converter Station, The Company in coordination with the Relevant Transmission Licensee may specify voltage limits at the HVDC Interface Point at which the DC Connected Power Park Module is capable of automatic disconnection.

ECC.6.1.4.2.4 For HVDC Interface Points which fall outside the scope of ECC.6.1.4.2.1, ECC.6.1.4.2.2 and ECC.6.1.4.2.3, The Company in coordination with the Relevant Transmission Licensee shall specify any applicable requirements at the Grid Entry Point or User System Entry Point.

ECC.6.1.4.2.5 Where the nominal frequency of the AC collector System which is connected to an HVDC Interface Point is at a value other than 50Hz, the voltage ranges and time periods specified by The Company in coordination with the Relevant Transmission Licensee shall be proportional to the values specified in Table ECC.6.1.4.2(a) and Table ECC.6.1.4.2(b).

ECC.6.1.4.3 Grid Voltage Variations for all Remote End HVDC Converters

ECC.6.1.4.3.1 All Remote End HVDC Converter Stations shall be capable of staying connected to the HVDC Interface Point and operating within the voltage ranges and time periods specified in Tables ECC.6.1.4.3(a) and ECC.6.1.4.3(b) below. The applicable voltage range and time periods specified are selected based on the reference 1pu voltage.

<table>
<thead>
<tr>
<th>Voltage Range (pu)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.85pu – 0.9pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td>0.9pu – 1.1pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td>1.1pu – 1.15pu</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

Table ECC.6.1.4.3(a) – Minimum time periods for which a Remote End HVDC Converter shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is 110kV or above and less than 300kV.

<table>
<thead>
<tr>
<th>Voltage Range (pu)</th>
<th>Time Period for Operation (s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.85pu – 0.9pu</td>
<td>60 minutes</td>
</tr>
<tr>
<td>0.9pu – 1.05pu</td>
<td>Unlimited</td>
</tr>
<tr>
<td>1.05pu – 1.15pu</td>
<td>15 minutes</td>
</tr>
</tbody>
</table>

Table ECC.6.1.4.3(b) – Minimum time periods for which a Remote End HVDC Converter shall be capable of operating for different voltages deviating from reference 1pu without disconnecting from the network where the nominal voltage base is from 300kV up to and including 400kV.
ECC.6.1.4.3.2 The Company and a HVDC System Owner may agree greater voltage ranges or longer minimum operating times which shall be in accordance with the requirements of ECC.6.1.4.2.

ECC.6.1.4.3.4 For HVDC Interface Points which fall outside the scope of ECC.6.1.4.3.1 The Company in coordination with the Relevant Transmission Licensee shall specify any applicable requirements at the Grid Entry Point or User System Entry Point.

ECC.6.1.4.3.5 Where the nominal frequency of the AC collector System which is connected to an HVDC Interface Point is at a value other than 50Hz, the voltage ranges and time periods specified by The Company in coordination with the Relevant Transmission Licensee shall be proportional to the values specified in Table ECC.6.1.4.3(a) and Table ECC.6.1.4.3(b)

Voltage Waveform Quality

ECC.6.1.5 All Plant and Apparatus connected to the National Electricity Transmission System, and that part of the National Electricity Transmission System at each Connection Site or, in the case of OTSDUW Plant and Apparatus, at each Interface Point, should be capable of withstanding the following distortions of the voltage waveform in respect of harmonic content and phase unbalance:

(a) Harmonic Content

The Electromagnetic Compatibility Levels for harmonic distortion on the Onshore Transmission System from all sources under both Planned Outage and fault outage conditions, (unless abnormal conditions prevail) shall comply with Engineering Recommendation G5. The Electromagnetic Compatibility Levels for harmonic distortion on an Offshore Transmission System will be defined in relevant Bilateral Agreements.

Engineering Recommendation G5 contains planning criteria which The Company will apply to the connection of non-linear Load to the National Electricity Transmission System, which may result in harmonic emission limits being specified for these Loads in the relevant Bilateral Agreement. The application of the planning criteria will take into account the position of existing GB Code User’s and EU Code Users’ Plant and Apparatus (and OTSDUW Plant and Apparatus) in relation to harmonic emissions. EU Code Users must ensure that connection of distorting loads to their User Systems do not cause any harmonic emission limits specified in the Bilateral Agreement, or where no such limits are specified, the relevant planning levels specified in Engineering Recommendation G5 to be exceeded.

(b) Phase Unbalance

Under Planned Outage conditions, the weekly 95 percentile of Phase (Voltage) Unbalance, calculated in accordance with IEC 61000-4-30 and IEC 61000-3-13, on the National Electricity Transmission System for voltages above 150kV should remain, in England and Wales, below 1.5%, and in Scotland, below 2%, and for voltages of 150kV and below, across GB below 2%, unless abnormal conditions prevail and Offshore (or in the case of OTSDUW, OTSDUW Plant and Apparatus) will be defined in relevant Bilateral Agreements.

The Phase Unbalance is calculated from the ratio of root mean square (rms) of negative phase sequence voltage to rms of positive phase sequence voltage, based on 10-minute average values, in accordance with IEC 61000-4-30.

ECC.6.1.6 Across GB, under the Planned Outage conditions stated in ECC.6.1.5(b) infrequent short duration peaks with a maximum value of 2% are permitted for Phase (Voltage) Unbalance, for voltages above 150kV, subject to the prior agreement of The Company under the Bilateral Agreement and in relation to OTSDUW, the Construction Agreement. The Company will only agree following a specific assessment of the impact of these levels on Transmission Apparatus and other Users Apparatus with which it is satisfied.

Voltage Fluctuations
ECC.6.1.7 Voltage changes at a **Point of Common Coupling** on the **Onshore Transmission System** shall not exceed:

(a) The limits specified in Table ECC.6.1.7(a) with the stated frequency of occurrence, where:

(i)  
\[
\% \Delta V_{\text{steady state}} = \left| 100 \times \frac{\Delta V_{\text{steady state}}}{V_n} \right| \quad \text{and} \quad \% \Delta V_{\text{max}} = 100 \times \frac{\Delta V_{\text{max}}}{V_n};
\]

(ii) \( V_n \) is the nominal system voltage;

(iii) \( V_{\text{steady state}} \) is the voltage at the end of a period of 1 s during which the rate of change of system voltage over time is \( \leq 0.5\% \);

(iv) \( \Delta V_{\text{steady state}} \) is the difference in voltage between the initial steady state voltage prior to the RVC (\( V_0 \)) and the final steady state voltage after the RVC (\( V_0' \));

(v) \( \Delta V_{\text{max}} \) is the absolute change in the system voltage relative to the initial steady state system voltage (\( V_0 \));

(vi) All voltages are the r.m.s. of the voltage measured over one cycle refreshed every half a cycle as per BS EN 61000-4-30; and

(vii) The applications in the ‘Example Applicability’ column are examples only and are not definitive.

<table>
<thead>
<tr>
<th>Category</th>
<th>Title</th>
<th>Maximum number of occurrence</th>
<th>Limits</th>
<th>Example Applicability</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Frequent events</td>
<td>(see NOTE 1)</td>
<td>As per Figure ECC.6.1.7 (1)</td>
<td>Any single or repetitive RVC that falls inside Figure ECC.6.1.7 (1)</td>
</tr>
</tbody>
</table>
| 2        | Infrequent events | 4 events in 1 calendar month (see NOTE 2) | As per Figure ECC.6.1.7 (2)  
\[
\% \Delta V_{\text{steady state}} \leq 3\%
\]  
For decrease in voltage:  
\[
\% \Delta V_{\text{max}} \leq 10\%
\]  
(see NOTE 3)  
For increase in voltage:  
\[
\% \Delta V_{\text{max}} \leq 6\%
\]  
(see NOTE 4) | Infrequent motor starting, transformer energisation, re-energisation (see NOTE 7) |
Table ECC.6.1.7 (a) – Planning levels for RVC

(b) The voltage change limit is the absolute maximum allowed of either the phase-to-earth voltage change or the phase-to-phase voltage change, whichever is the highest. The limits do not apply to single phasor equivalent voltages, e.g. positive phase sequence (PPS) voltages. For high impedance earthed systems, the maximum phase-to-phase, i.e. line voltage, should be used for assessment.

(c) The RVCs in Category 2 and 3 should not exceed the limits depicted in the time dependent characteristic shown in Figure ECC.6.1.7 (2) and Figure ECC.6.1.7 (3) respectively. These limits do not apply to: 1) fault clearance operations; or 2) immediate operations in response to fault conditions; or 3) operations relating to post fault system restoration (for the avoidance of doubt this third exception pertains to a fault that is external to the Users plant and apparatus).

(d) Any RVCs permitted in Category 2 and Category 3 should be at least 10 minutes apart.

(e) The value of $V_{\text{steady state}}$ should be established immediately prior to the start of a RVC. Following a RVC, the voltage should remain within the relevant envelope, as shown in Figures ECC.6.1.7 (1), ECC.6.1.7 (2), ECC.6.1.7 (3), until a $V_{\text{steady state}}$ condition has been satisfied.
Figure ECC.6.1.7 (1) — Voltage characteristic for frequent events

Figure ECC.6.1.7 (2) — Voltage characteristic for infrequent events

Figure ECC.6.1.7 (3) — Voltage characteristic for very infrequent events
(f) The voltage change between two steady state voltage conditions should not exceed 3%. (The limit is based on 3% of the nominal voltage of the system \( V_n \) as measured at the PCC. The step voltage change as measured at the customer’s supply terminals or equipment terminals could be greater. For example: The step voltage change limit stated in BS EN 61000-3-3 and BS EN 61000-3-11 is 3.3% when measured at the equipment terminals.)

(g) The limits apply to voltage changes measured at the Point of Common Coupling.

(h) Category 3 events that are planned should be notified to the Company in advance.

(i) For connections where voltage changes would constitute a risk to the National Electricity Transmission System or, in The Company’s view, the System of any GB Code User, Bilateral Agreements may include provision for The Company to reasonably limit the number of voltage changes in Category 2 or 3 to a lower number than specified in Table ECC.6.1.7(a) to ensure that the total number of voltage changes at the Point of Common Coupling across multiple Users remains within the limits of Table ECC.6.1.7(a).

(j) The planning levels applicable to Flicker Severity Short Term (Pst) and Flicker Severity Long Term (Plt) are set out in Table ECC.6.1.7(b).

<table>
<thead>
<tr>
<th>Supply system Nominal voltage</th>
<th>Planning level</th>
<th>Flicker Severity Short Term (Pst)</th>
<th>Flicker Severity Long Term (Plt)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Up to and including 33 kV</td>
<td></td>
<td>0.9</td>
<td>0.7</td>
</tr>
<tr>
<td>66kV and greater</td>
<td></td>
<td>0.8</td>
<td>0.6</td>
</tr>
</tbody>
</table>

NOTE 1: The magnitude of Pst is linear with respect to the magnitude of the voltage changes giving rise to it.

NOTE 2: Extreme caution is advised in allowing any excursions of Pst and Plt above the planning level.

Table ECC.6.7.1(b) — Planning levels for flicker

The values and figures referred to in this paragraph ECC.6.1.7 are derived from Engineering Recommendation P28 Issue 2.

ECC.6.1.8 Voltage fluctuations at a Point of Common Coupling with a fluctuating Load directly connected to an Offshore Transmission System (or in the case of OTSDUW, OTSDUW Plant and Apparatus) shall not exceed the limits set out in the Bilateral Agreement.

ECC.6.1.9 The Company shall ensure that Users’ Plant and Apparatus will not be subject to unacceptable Sub-Synchronous Oscillation conditions as specified in the relevant License Standards.

ECC.6.1.10 The Company shall ensure where necessary, and in consultation with Relevant Transmission Licensees where required, that any relevant site specific conditions applicable at a User’s Connection Site, including a description of the Sub-Synchronous Oscillation conditions considered in the application of the relevant License Standards, are set out in the User’s Bilateral Agreement.
ECC.6.2 Plant and Apparatus relating to Connection Sites and Interface Points and HVDC Interface Points

The following requirements apply to Plant and Apparatus relating to the Connection Point and OTSDUW Plant and Apparatus relating to the Interface Point (until the OTSUA Transfer Time), HVDC Interface Points relating to Remote End HVDC Converters and Connection Points which (except as otherwise provided in the relevant paragraph) each EU Code User must ensure are complied with in relation to its Plant and Apparatus and which in the case of ECC.6.2.2.2, ECC.6.2.3.1.1 and ECC.6.2.1.1(b) only, The Company must ensure are complied with in relation to Transmission Plant and Apparatus, as provided in those paragraphs.

ECC.6.2.1 General Requirements

ECC.6.2.1.1 (a) The design of connections between the National Electricity Transmission System and:

(i) any Power Generating Module Generating Unit (other than a CCGT Unit or Power Park Unit) HVDC Equipment, Power Park Module or CCGT Module, or

(ii) any Network Operator’s User System, or

(iii) Non-Embedded Customers equipment;

will be consistent with the Licence Standards.

In the case of OTSDUW, the design of the OTSUA’s connections at the Interface Point and Connection Point will be consistent with Licence Standards.

(b) The National Electricity Transmission System (and any OTSDUW Plant and Apparatus) at nominal System voltages of 132kV and above is/shall be designed to be earthed with an Earth Fault Factor of, in England and Wales or Offshore, below 1.4 and in Scotland, below 1.5. Under fault conditions the rated Frequency component of voltage could fall transiently to zero on one or more phases or, in England and Wales, rise to 140% phase-to-earth voltage, or in Scotland, rise to 150% phase-to-earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase-to-earth.

(c) For connections to the National Electricity Transmission System at nominal System voltages of below 132kV the earthing requirements and voltage rise conditions will be advised by The Company as soon as practicable prior to connection and in the case of OTSDUW Plant and Apparatus shall be advised to The Company by the EU Code User.

ECC.6.2.1.2 Substation Plant and Apparatus

(a) The following provisions shall apply to all Plant and Apparatus which is connected at the voltage of the Connection Point (and OTSDUW Plant and Apparatus at the Interface Point ) and which is contained in equipment bays that are within the Transmission busbar Protection zone at the Connection Point. This includes circuit breakers, switch disconnectors, disconnectors, Earthing Devices, power transformers, voltage transformers, reactors, current transformers, surge arresters, bushings, neutral equipment, capacitors, line traps, coupling devices, external insulation and insulation co-ordination devices. Where necessary, this is as more precisely defined in the Bilateral Agreement.

(i) Plant and/or Apparatus in respect of EU Code Users connecting to a new Connection Point (including OTSDUW Plant and Apparatus at the Interface Point )

Each item of such Plant and/or Apparatus installed in relation to a new Connection Point (or OTSDUW Plant and Apparatus at the Interface Point or Remote End HVDC Converter Station at the HVDC Interface Point) shall comply with the relevant Technical Specifications and any further requirements identified by The Company, acting reasonably, to reflect the options to be followed within the Technical Specifications and/or to complement if necessary the Technical Specification.
Specifications so as to enable The Company to comply with its obligations in relation to the National Electricity Transmission System or the Relevant Transmission Licensee to comply with its obligations in relation to its Transmission System. This information, including the application dates of the relevant Technical Specifications, will be as specified in the Bilateral Agreement.

(ii) EU Code User’s Plant and/or Apparatus connecting to an existing Connection Point (including OTSDUW Plant and Apparatus at the Interface Point)

Each new additional and/or replacement item of such Plant and/or Apparatus installed in relation to a change to an existing Connection Point (or OTSDUW Plant and Apparatus at the Interface Point and Connection Point or Remote HVDC Converter Stations at the HVDC Interface Point) shall comply with the standards/specifications applicable when the change was designed, or such other standards/specifications as necessary to ensure that the item of Plant and/or Apparatus is reasonably fit for its intended purpose having due regard to the obligations of The Company, the relevant User and the Relevant Transmission Licensee under their respective Licences. Where appropriate this information, including the application dates of the relevant standards/specifications, will be as specified in the varied Bilateral Agreement.

(iii) Used Plant and/or Apparatus being moved, re-used or modified

If, after its installation, any such item of Plant and/or Apparatus is subsequently:

moved to a new location; or

used for a different purpose; or

otherwise modified;

then the standards/specifications as described in (i) or (ii) above as applicable will apply as appropriate to such Plant and/or Apparatus, which must be reasonably fit for its intended purpose having due regard to the obligations of The Company, the relevant User and the Relevant Transmission Licensee under their respective Licences.

(b) The Company shall at all times maintain a list of those Technical Specifications and additional requirements which might be applicable under this ECC.6.2.1.2 and which may be referenced by The Company in the Bilateral Agreement. The Company shall provide a copy of the list upon request to any EU Code User. The Company shall also provide a copy of the list to any EU Code User upon receipt of an application form for a Bilateral Agreement for a new Connection Point.

(c) Where the EU Code User provides The Company with information and/or test reports in respect of Plant and/or Apparatus which the EU Code User reasonably believes demonstrate the compliance of such items with the provisions of a Technical Specification then The Company shall promptly and without unreasonable delay give due and proper consideration to such information.

(d) Plant and Apparatus shall be designed, manufactured and tested in premises with an accredited certificate in accordance with the quality assurance requirements of the relevant standard in the BS EN ISO 9000 series (or equivalent as reasonably approved by The Company) or in respect of test premises which do not include a manufacturing facility premises with an accredited certificate in accordance with BS EN 45001.

(e) Each connection between a User and the National Electricity Transmission System must be controlled by a circuit-breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the point of connection. The Seven Year Statement gives values of short circuit current and the rating of Transmission circuit breakers at existing and committed Connection Points for future years.
(f) Each connection between a Generator undertaking OTSDUW or an Onshore Transmission Licensee, must be controlled by a circuit breaker (or circuit breakers) capable of interrupting the maximum short circuit current at the Transmission Interface Point. The Seven Year Statement gives values of short circuit current and the rating of Transmission circuit breakers at existing and committed Transmission Interface Points for future years.

ECC.6.2.2 Requirements at Connection Points or, in the case of OTSDUW at Interface Points that relate to Generators or OTSDUW Plant and Apparatus

ECC.6.2.2.1 Not Used.

ECC.6.2.2.2 Power Generating Module, OTSDUW Plant and Apparatus, HVDC Equipment and Power Station Protection Arrangements

ECC.6.2.2.2.1 Minimum Requirements

Protection of Power Generating Modules (other than Power Park Units), HVDC Equipment, OTSDUW Plant and Apparatus and their connections to the National Electricity Transmission System shall meet the requirements given below. These are necessary to reduce the impact on the National Electricity Transmission System of faults on OTSDUW Plant and Apparatus circuits or circuits owned by Generators (including DC Connected Power Park Modules) or HVDC System Owners.

ECC.6.2.2.2.2 Fault Clearance Times

(a) The required fault clearance time for faults on the Generator's (including DC Connected Power Park Modules) or HVDC System Owner's equipment directly connected to the National Electricity Transmission System or OTSDUW Plant and Apparatus and for faults on the National Electricity Transmission System directly connected to the EU Generator (including DC Connected Power Park Modules) or HVDC System Owner's equipment or OTSDUW Plant and Apparatus, from fault inception to the circuit breaker arc extinction, shall be set out in the Bilateral Agreement. The fault clearance time specified in the Bilateral Agreement shall not be shorter than the durations specified below:

(i) 80ms for connections operating at a nominal voltage of greater than 300kV
(ii) 100ms for connections operating at a nominal voltage of greater than 132kV and up to 300kV
(iii) 120ms for connections operating at a nominal voltage of 132kV and below

but this shall not prevent the User or The Company or the Relevant Transmission Licensee or the EU Generator (including in respect of OTSDUW Plant and Apparatus and DC Connected Power Park Modules) from selecting a shorter fault clearance time on their own Plant and Apparatus provided Discrimination is achieved.

A longer fault clearance time may be specified in the Bilateral Agreement for faults on the National Electricity Transmission System. A longer fault clearance time for faults on the EU Generator or HVDC System Owner's equipment or OTSDUW Plant and Apparatus may be agreed with The Company in accordance with the terms of the Bilateral Agreement but only if System requirements, in The Company's view, permit. The probability that the fault clearance time stated in the Bilateral Agreement will be exceeded by any given fault, must be less than 2%.

(b) In the event that the required fault clearance time is not met as a result of failure to operate on the Main Protection System(s) provided, the Generators or HVDC System Owners or Generators in the case of OTSDUW Plant and Apparatus shall, except as specified below provide Independent Back-Up Protection. The Relevant Transmission Licensee will also provide Back-Up Protection and the Relevant Transmission Licensee's and the User's Back-Up Protections will be co-ordinated so as to provide Discrimination.
On a Power Generating Module (other than a Power Park Unit), HVDC Equipment or OTSDUW Plant and Apparatus and connected to the National Electricity Transmission System operating at a nominal voltage of greater than 132kV and where two Independent Main Protections are provided to clear faults on the HV Connections within the required fault clearance time, the Back-Up Protection provided by EU Generators (including in respect of OTSDUW Plant and Apparatus and DC Connected Power Park Modules) and HVDC System Owners shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections. Where two Independent Main Protections are installed the Back-Up Protection may be integrated into one (or both) of the Independent Main Protection relays.

On a Power Generating Module (other than a Power Park Unit), HVDC Equipment or OTSDUW Plant and Apparatus and connected to the National Electricity Transmission System at 132 kV and below and where only one Main Protection is provided to clear faults on the HV Connections within the required fault clearance time, the Independent Back-Up Protection provided by the Generator (including in respect of OTSDUW Plant and Apparatus and DC Connected Power Park Modules) and the HVDC System Owner shall operate to give a fault clearance time of no longer than 300ms at the minimum infeed for normal operation for faults on the HV Connections.

A Power Generating Module (other than a Power Park Unit), HVDC Equipment or OTSDUW Plant and Apparatus with Back-Up Protection or Independent Back-Up Protection will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the National Electricity Transmission System by breaker fail Protection at a nominal voltage of greater than 132kV or of a fault cleared by Back-Up Protection where the EU Generator (including in the case of OTSDUW Plant and Apparatus or DC Connected Power Park Module) or HVDC System is connected at 132kV and below. This will permit Discrimination between the Generator in respect of OTSDUW Plant and Apparatus or DC Connected Power Park Modules or HVDC System Owners’ Back-Up Protection or Independent Back-Up Protection and the Back-Up Protection provided on the National Electricity Transmission System and other Users’ Systems.

(c) When the Power Generating Module (other than Power Park Units), or the HVDC Equipment or OTSDUW Plant and Apparatus is connected to the National Electricity Transmission System operating at a nominal voltage of greater than 132kV, and in Scotland and Offshore also at 132kV, and a circuit breaker is provided by the Generator (including in respect of OTSDUW Plant and Apparatus or DC Connected Power Park Modules) or the HVDC System owner, or the Relevant Transmission Licensee, as the case may be, to interrupt fault current interchange with the National Electricity Transmission System, or Generator’s System, or HVDC System Owner’s System, as the case may be, circuit breaker fail Protection shall be provided by the Generator (including in respect of OTSDUW Plant and Apparatus or DC Connected Power Park Modules) or HVDC System Owner, or the Relevant Transmission Licensee, as the case may be, on this circuit breaker. In the event, following operation of a Protection system, of a failure to interrupt fault current by these circuit-breakers within the Fault Current Interruption Time, the circuit breaker fail Protection is required to initiate tripping of all the necessary electrically adjacent circuit-breakers so as to interrupt the fault current within the next 200ms.

(d) The target performance for the System Fault Dependability Index shall be not less than 99%. This is a measure of the ability of Protection to initiate successful tripping of circuit breakers which are associated with the faulty item of Apparatus.

ECC.6.2.2.3 Equipment including Protection equipment to be provided
The Relevant Transmission Licensee shall specify the Protection schemes and settings necessary to protect the National Electricity Transmission System, taking into account the characteristics of the Power Generating Module or HVDC Equipment.

The protection schemes needed for the Power Generating Module or HVDC Equipment and the National Electricity Transmission System as well as the settings relevant to the Power Generating Module and/or HVDC Equipment shall be coordinated and agreed between The Company and the EU Generator or HVDC System Owner. The agreed Protection schemes and settings will be specified in the Bilateral Agreement.

The protection schemes and settings for internal electrical faults must not prevent the Power Generating Module or HVDC Equipment from satisfying the requirements of the Grid Code although EU Generators should be aware of the requirements of ECC.6.3.13.1; electrical Protection of the Power Generating Module or HVDC Equipment shall take precedence over operational controls, taking into account the security of the National Electricity Transmission System and the health and safety of personnel, as well as mitigating any damage to the Power Generating Module or HVDC Equipment.

ECC.6.2.2.3.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement. In this ECC the term "interconnecting connections" means the primary conductors from the current transformer accommodation on the circuit side of the circuit breaker to the Connection Point or the primary conductors from the current transformer accommodation on the circuit side of the OTSDUW Plant and Apparatus of the circuit breaker to the Transmission Interface Point.

ECC.6.2.2.3.2 Circuit-breaker fail Protection

The EU Generator or HVDC System Owner will install circuit breaker fail Protection equipment in accordance with the requirements of the Bilateral Agreement. The EU Generator or HVDC System Owner will also provide a back-trip signal in the event of loss of air from its pressurised head circuit breakers, during the Power Generating Module (other than a CCGT Unit or Power Park Unit) or HVDC Equipment run-up sequence, where these circuit breakers are installed.

ECC.6.2.2.3.3 Loss of Excitation

The EU Generator must provide Protection to detect loss of excitation in respect of each of its Generating Units within a Synchronous Power Generating Module to initiate a Generating Unit trip.

ECC.6.2.2.3.4 Pole-Slipping Protection

Where, in The Company's reasonable opinion, System requirements dictate, The Company will specify in the Bilateral Agreement a requirement for EU Generators to fit pole-slipping Protection on their Generating Units within each Synchronous Power Generating Module.

ECC.6.2.2.3.5 Signals for Tariff Metering

EU Generators and HVDC System Owners will install current and voltage transformers supplying all tariff meters at a voltage to be specified in, and in accordance with, the Bilateral Agreement.

ECC.6.2.2.3.6 Commissioning of Protection Systems

No EU Generator or HVDC System Owner equipment shall be energised until the Protection settings have been finalised. The EU Generator or HVDC System Owner shall agree with The Company (in coordination with the Relevant Transmission Licensee) and carry out a combined commissioning programme for the Protection systems, and generally, to a minimum standard as specified in the Bilateral Agreement.

ECC.6.2.2.4 Work on Protection Equipment
No busbar Protection, mesh corner Protection, circuit-breaker fail Protection relays, AC or DC wiring (other than power supplies or DC tripping associated with the Power Generating Module, HVDC Equipment itself) may be worked upon or altered by the EU Generator or HVDC System Owner personnel in the absence of a representative of the Relevant Transmission Licensee or written authority from the Relevant Transmission Licensee to perform such work or alterations in the absence of a representative of the Relevant Transmission Licensee.

ECC.6.2.2.5 Relay Settings

Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement and in relation to OTSDUW Plant and Apparatus, across the Interface Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

ECC.6.2.2.6 Changes to Protection Schemes and HVDC System Control Modes

ECC.6.2.2.6.1 Any subsequent alterations to the protection settings (whether by The Company, the Relevant Transmission Licensee, the EU Generator or the HVDC System Owner) shall be agreed between The Company (in co-ordination with the Relevant Transmission Licensee) and the EU Generator or HVDC System Owner in accordance with the Grid Code (ECC.6.2.2.5). No alterations are to be made to any protection schemes unless agreement has been reached between The Company, the Relevant Transmission Licensee, the EU Generator or HVDC System Owner.

ECC.6.2.2.6.2 The parameters of different control modes of the HVDC System shall be able to be changed in the HVDC Converter Station, if required by The Company in coordination with the Relevant Transmission Licensee and in accordance with ECC.6.2.2.6.4.

ECC.6.2.2.6.3 Any change to the schemes or settings of parameters of the different control modes and protection of the HVDC System including the procedure shall be agreed with The Company in coordination with the Relevant Transmission Licensee and the HVDC System Owner.

ECC.6.2.2.6.4 The control modes and associated set points shall be capable of being changed remotely, as specified by The Company in coordination with the Relevant Transmission Licensee.

ECC.6.2.2.7 Control Schemes and Settings

ECC.6.2.2.7.1 The schemes and settings of the different control devices on the Power Generating Module and HVDC Equipment that are necessary for Transmission System stability and for taking emergency action shall be agreed with The Company in coordination with the Relevant Transmission Licensee and the EU Generator or HVDC System Owner.

ECC.6.2.2.7.2 Subject to the requirements of ECC.6.2.2.7.1 any changes to the schemes and settings, defined in ECC.6.2.2.7.1, of the different control devices of the Power Generating Module or HVDC Equipment shall be coordinated and agreed between, the Relevant Transmission Licensee, the EU Generator and HVDC System Owner.

ECC.6.2.2.8 Ranking of Protection and Control

ECC.6.2.2.8.1 The Company in coordination with Relevant Transmission Licensees, shall agree and coordinate the protection and control devices of EU Generators Plant and Apparatus in accordance with the following general priority ranking (from highest to lowest):

(i) The interface between the National Electricity Transmission System and the Power Generating Module or HVDC Equipment Protection equipment;
(ii) frequency control (active power adjustment);
(iii) power restriction; and
(iv) power gradient constraint;
ECC.6.2.2.8.2 A control scheme, specified by the HVDC System Owner consisting of different control modes, including the settings of the specific parameters, shall be coordinated and agreed between The Company in coordination with the Relevant Transmission Licensee and the HVDC System Owner. These details would be specified in the Bilateral Agreement.

ECC.6.2.2.8.3 The Company in coordination with Relevant Transmission Licensees, shall agree and coordinate the protection and control devices of HVDC System Owners Plant and Apparatus in accordance with the following general priority ranking (from highest to lowest)

(i) The interface between the National Electricity Transmission System and HVDC System Protection equipment;

(ii) Active Power control for emergency assistance

(iii) automatic remedial actions as specified in ECC.6.3.6.1.2.5

(iv) Limited Frequency Sensitive Mode (LFSM) of operation;

(v) Frequency Sensitive Mode of operation and Frequency control; and

(vi) power gradient constraint.

ECC.6.2.2.9 Synchronising

ECC.6.2.2.9.1 For any Power Generating Module directly connected to the National Electricity Transmission System or Type D Power Generating Module, synchronisation shall be performed by the EU Generator only after instruction by The Company in accordance with the requirements of BC.2.5.2.

ECC.6.2.2.9.2 Each Power Generating Module directly connected to the National Electricity Transmission System or Type D Power Generating Module shall be equipped with the necessary synchronisation facilities. Synchronisation shall be possible within the range of frequencies specified in ECC.6.1.2.

ECC.6.2.2.9.3 The requirements for synchronising equipment shall be specified in accordance with the requirements in the Electrical Standards listed in the annex to the General Conditions. The synchronisation settings shall include the following elements below. Any variation to these requirements shall be pursuant to the terms of the Bilateral Agreement.

(a) voltage

(b) Frequency

(c) phase angle range

(d) phase sequence

(e) deviation of voltage and Frequency

ECC.6.2.2.9.4 HVDC Equipment shall be required to satisfy the requirements of ECC.6.2.2.9.1 – ECC.6.2.2.9.3. In addition, unless otherwise specified by The Company, during the synchronisation of a DC Connected Power Park Module to the National Electricity Transmission System, any HVDC Equipment shall have the capability to limit any steady state voltage changes to the limits specified within ECC.6.1.7 or ECC.6.1.8 (as applicable) which shall not exceed 5% of the pre-synchronisation voltage. The Company in coordination with the Relevant Transmission Licensee shall specify any additional requirements for the maximum magnitude, duration and measurement of the voltage transients over and above those defined in ECC.6.1.7 and ECC.6.1.8 in the Bilateral Agreement.

ECC.6.2.2.9.5 EU Generators in respect of DC Connected Power Park Modules shall also provide output synchronisation signals specified by The Company in co-ordination with the Relevant Transmission Licensee.
In addition to the requirements of ECC.6.2.2.9.1 to ECC.6.2.2.9.5, **EU Generators** and **HVDC System Owners** should also be aware of the requirements of ECC.6.5.10 relating to busbar voltage.

**ECC.6.2.2.9.10 HVDC Parameters and Settings**

**ECC.6.2.2.9.10.1** The parameters and settings of the main control functions of an **HVDC System** shall be agreed between the **HVDC System** owner and **The Company**, in coordination with the **Relevant Transmission Licensee**. The parameters and settings shall be implemented within such a control hierarchy that makes their modification possible if necessary. Those main control functions are at least:

(b) **Frequency Sensitive Modes** (FSM, LFSM-O, LFSM-U);

(c) **Frequency** control, if applicable;

(d) **Reactive Power** control mode, if applicable;

(e) power oscillation damping capability;

(f) subsynchronous torsional interaction damping capability.

**ECC.6.2.2.11 Automatic Reconnection**

**ECC.6.2.2.11.1** **EU Generators** in respect of **Type A**, **Type B**, **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) which have signed a **CUSC Contract** with **The Company** are not permitted to automatically reconnect to the **Total System** without instruction from **The Company**. **The Company** will issue instructions for reconnection or re-synchronisation in accordance with the requirements of BC2.5.2. Where synchronising is permitted in accordance with BC2.5.2, the voltage and frequency at the **Grid Entry Point** or **User System Entry Point** shall be within the limits defined in ECC.6.1.2 and ECC.6.1.4 and the ramp rate limits pursuant to BC1.A.1.1. For the avoidance of doubt this requirement does not apply to **EU Generators** who are not required to satisfy the requirements of the Balancing Codes.

**ECC.6.2.2.12 Automatic Disconnection**

**ECC.6.2.2.12.1** No **Power Generating Module** or **HVDC Equipment** shall disconnect within the frequency range or voltage range defined in ECC.6.1.2 and ECC.6.1.4.

**ECC.6.2.2.13 Special Provisions relating to Power Generating Modules embedded within Industrial Sites which supply electricity as a bi-product of their industrial process**

**ECC.6.2.2.13.1** **Generators** in respect of **Power Generating Modules** which form part of an industrial network, where the **Power Generating Module** is used to supply critical loads within the industrial process shall be permitted to operate isolated from the **Total System** if agreed with **The Company** in the **Bilateral Agreement**.

**ECC.6.2.2.13.2** Except for the requirements of ECC.6.3.3 and ECC.6.3.7.1, **Power Generating Modules** which are embedded within industrial sites are not required to satisfy the requirements of ECC.6.3.6.2.1 and ECC.6.3.9. In this case this exception would only apply to **Power Generating Modules** on industrial sites used for combined heat and power production which are embedded in the network of an industrial site where all the following criteria are met.

(a) The primary purpose of these sites is to produce heat for production processes of the industrial site concerned,

(b) Heat and power generation is inextricably interlinked, that is to say any change to heat generation results inadvertently in a change of active power generating and visa versa.

(c) The **Power Generating Modules** are of **Type A**, **Type B** or **Type C**.

(d) Combined heat and power generating facilities shall be assessed on the basis of their electrical **Maximum Capacity**.
Fault Clearance Times

(a) The required fault clearance time for faults on Network Operator and Non-Embedded Customer equipment directly connected to the National Electricity Transmission System, and for faults on the National Electricity Transmission System directly connected to the Network Operator’s or Non-Embedded Customer’s equipment, from fault inception to the circuit breaker arc extinction, shall be set out in each Bilateral Agreement. The fault clearance time specified in the Bilateral Agreement shall not be shorter than the durations specified below:

(i) 80ms for connections operating at a nominal voltage of greater than 300kV
(ii) 100ms for connections operating at a nominal voltage of greater than 132kV and up to 300kV
(iii) 120ms for connections operating at a nominal voltage of greater than 132kV and below

but this shall not prevent the User or The Company or Relevant Transmission Licensee from selecting a shorter fault clearance time on its own Plant and Apparatus provided Discrimination is achieved.

For the purpose of establishing the Protection requirements in accordance with ECC.6.2.3.1.1 only, the point of connection of the Network Operator or Non-Embedded Customer equipment to the National Electricity Transmission System shall be deemed to be the low voltage busbars at an EU Grid Supply Point, irrespective of the ownership of the equipment at the EU Grid Supply Point.

A longer fault clearance time may be specified in the Bilateral Agreement for faults on the National Electricity Transmission System. A longer fault clearance time for faults on the Network Operator and Non-Embedded Customers equipment may be agreed with The Company in accordance with the terms of the Bilateral Agreement but only if System requirements in The Company’s view permit. The probability that the fault clearance time stated in the Bilateral Agreement will be exceeded by any given fault must be less than 2%.

(b) (i) For the event of failure of the Protection systems provided to meet the above fault clearance time requirements, Back-Up Protection shall be provided by the Network Operator or Non-Embedded Customer as the case may be.

(ii) The Relevant Transmission Licensee will also provide Back-Up Protection, which will result in a fault clearance time longer than that specified for the Network Operator or Non-Embedded Customer Back-Up Protection so as to provide Discrimination.

(iii) For connections with the National Electricity Transmission System at 132kV and below, it is normally required that the Back-Up Protection on the National Electricity Transmission System shall discriminate with the Network Operator or Non-Embedded Customer’s Back-Up Protection.

(iv) For connections with the National Electricity Transmission System operating at a nominal voltage greater than 132kV, the Back-Up Protection will be provided by the Network Operator or Non-Embedded Customer, as the case may be, with a fault clearance time not longer than 300ms for faults on the Network Operator’s or Non-Embedded Customer’s Apparatus.
(v) Such Protection will also be required to withstand, without tripping, the loading incurred during the clearance of a fault on the National Electricity Transmission System by breaker fail Protection operating at a nominal voltage of greater than 132kV. This will permit Discrimination between Network Operator’s Back-Up Protection or Non-Embedded Customer’s Back-Up Protection, as the case may be, and Back-Up Protection provided on the National Electricity Transmission System and other User Systems. The requirement for and level of Discrimination required will be specified in the Bilateral Agreement.

(c) (i) Where the Network Operator or Non-Embedded Customer is connected to part of the National Electricity Transmission System operating at a nominal voltage greater than 132kV and in Scotland also at 132kV, and a circuit breaker is provided by the Network Operator or Non-Embedded Customer, or the Relevant Transmission Licensee, as the case may be, to interrupt the interchange of fault current with the National Electricity Transmission System or the System of the Network Operator or Non-Embedded Customer, as the case may be, circuit breaker fail Protection will be provided by the Network Operator or Non-Embedded Customer, or the Relevant Transmission Licensee, as the case may be, on this circuit breaker.

(ii) In the event, following operation of a Protection system, of a failure to interrupt fault current by these circuit-breakers within the Fault Current Interruption Time, the circuit breaker fail Protection is required to initiate tripping of all the necessary electrically adjacent circuit-breakers so as to interrupt the fault current within the next 200ms.

(d) The target performance for the System Fault Dependability Index shall be not less than 99%. This is a measure of the ability of Protection to initiate successful tripping of circuit breakers which are associated with the faulty items of Apparatus.
ECC.6.2.3.2 Fault Disconnection Facilities

(a) Where no Transmission circuit breaker is provided at the User's connection voltage, the User must provide The Company with the means of tripping all the User's circuit breakers necessary to isolate faults or System abnormalities on the National Electricity Transmission System. In these circumstances, for faults on the User's System, the User's Protection should also trip higher voltage Transmission circuit breakers. These tripping facilities shall be in accordance with the requirements specified in the Bilateral Agreement.

(b) The Company may require the installation of a System to Generator Operational Intertripping Scheme in order to enable the timely restoration of circuits following power System fault(s). These requirements shall be set out in the relevant Bilateral Agreement.

ECC.6.2.3.3 Automatic Switching Equipment

Where automatic reclosure of Transmission circuit breakers is required following faults on the User's System, automatic switching equipment shall be provided in accordance with the requirements specified in the Bilateral Agreement.

ECC.6.2.3.4 Relay Settings

Protection and relay settings will be co-ordinated (both on connection and subsequently) across the Connection Point in accordance with the Bilateral Agreement to ensure effective disconnection of faulty Apparatus.

ECC.6.2.3.5 Work on Protection equipment

Where a Transmission Licensee owns the busbar at the Connection Point, no busbar Protection, mesh corner Protection relays, AC or DC wiring (other than power supplies or DC tripping associated with the Network Operator or Non-Embedded Customer's Apparatus itself) may be worked upon or altered by the Network Operator or Non-Embedded Customer personnel in the absence of a representative of the Relevant Transmission Licensee or written authority from the Relevant Transmission Licensee to perform such work or alterations in the absence of a representative of the Relevant Transmission Licensee.

ECC.6.2.3.6 Equipment including Protection equipment to be provided

The Company in coordination with the Relevant Transmission Licensee shall specify and agree the Protection schemes and settings at each EU Grid Supply Point required to protect the National Electricity Transmission System in accordance with the characteristics of the Network Operator's or Non Embedded Customer's System. The Company in coordination with the Relevant Transmission Licensee and the Network Operator or Non Embedded Customer shall agree on the protection schemes and settings in respect of the busbar protection zone in respect of each EU Grid Supply Point.

Protection of the Network Operator's or Non Embedded Customer's System shall take precedence over operational controls whilst respecting the security of the National Electricity Transmission System and the health and safety of staff and the public.

ECC.6.2.3.6.1 Protection of Interconnecting Connections

The requirements for the provision of Protection equipment for interconnecting connections will be specified in the Bilateral Agreement.

ECC.6.2.3.7 Changes to Protection Schemes at EU Grid Supply Points

Any subsequent alterations to the busbar protection settings at the EU Grid Supply Point (whether by The Company, the Relevant Transmission Licensee, the Network Operator or the Non Embedded Customer) shall be agreed between The Company (in co-ordination with the Relevant Transmission Licensee) and the Network Operator or Non Embedded Customer in accordance with the Grid Code (ECC.6.2.3.4). No alterations are to be made to any busbar protection schemes unless agreement has been reached between The Company,
the Relevant Transmission Licensee, the Network Operator or Non Embedded Customer.

No Network Operator or Non Embedded Customer equipment shall be energised until the Protection settings have been agreed prior to commissioning. The Network Operator or Non Embedded Customer shall agree with The Company (in coordination with the Relevant Transmission Licensee) and carry out a combined commissioning programme for the Protection systems, and generally, to a minimum standard as specified in the Bilateral Agreement.

ECC.6.2.3.8 Control Requirements

ECC.6.2.3.8.1 The Company in coordination with the Relevant Transmission Licensee and the Network Operator or Non Embedded Customer shall agree on the control schemes and settings at each EU Grid Supply Point of the different control devices of the Network Operator’s or Non Embedded Customer’s System relevant for security of the National Electricity Transmission System. Such requirements would be pursuant to the terms of the Bilateral Agreement which shall also cover at least the following elements:

(a) Isolated (National Electricity Transmission System) operation;
(b) Damping of oscillations;
(c) Disturbances to the National Electricity Transmission System;
(d) Automatic switching to emergency supply and restoration to normal topology;
(e) Automatic circuit breaker re-closure (on 1-phase faults).

ECC.6.2.3.8.2 Subject to the requirements of ECC.6.2.3.8.1 any changes to the schemes and settings, defined in ECC.6.2.3.8.1 of the different control devices of the Network Operator’s or Non-Embedded Customer’s System at the EU Grid Supply Point shall be coordinated and agreed between The Company, the Relevant Transmission Licensee, the Network Operator or Non Embedded Customer.

ECC.6.2.3.9 Ranking of Protection and Control

ECC.6.2.3.9.1 The Network Operator or the Non Embedded Customer who owns or operates an EU Grid Supply Point shall set the Protection and control devices of its System, in compliance with the following priority ranking, organised in decreasing order of importance:

(a) National Electricity Transmission System Protection;
(b) Protection equipment at each EU Grid Supply Point;
(c) Frequency control (Active Power adjustment);
(d) Power restriction.

ECC.6.2.3.10 Synchronising

ECC.6.2.3.10.1 Each Network Operator or Non Embedded Customer at each EU Grid Supply Point shall be capable of synchronisation within the range of frequencies specified in ECC.6.1.2 unless otherwise agreed with The Company.

ECC.6.2.3.10.2 The Company and the Network Operator or Non Embedded Customer shall agree on the settings of the synchronisation equipment at each EU Grid Supply Point prior to the Completion Date. The Company and the relevant Network Operator or Non-Embedded Customer shall agree the synchronisation settings which shall include the following elements.

(a) Voltage;
(b) Frequency;
(c) phase angle range;
(d) deviation of voltage and Frequency.
ECC.6.3 GENERAL POWER GENERATING MODULE, OTSDUW AND HVDC EQUIPMENT REQUIREMENTS

ECC.6.3.1 This section sets out the technical and design criteria and performance requirements for Power Generating Modules (which includes Electricity Storage Modules) and HVDC Equipment (whether directly connected to the National Electricity Transmission System or Embedded) and (where provided in this section) OTSDUW Plant and Apparatus which each Generator or HVDC System Owner must ensure are complied with in relation to its Power Generating Modules, HVDC Equipment and OTSDUW Plant and Apparatus. References to Power Generating Modules, HVDC Equipment in this ECC.6.3 should be read accordingly. For the avoidance of doubt, the requirements applicable to Synchronous Power Generating Modules also apply to Synchronous Electricity Storage Modules and the requirements applicable to Power Park Modules apply to Non-Synchronous Electricity Storage Modules. In addition, the requirements applicable to Electricity Storage Modules also apply irrespective of whether the Electricity Storage Module operates in such a mode as to import or export power from the Total System.

Plant Performance Requirements

ECC.6.3.2 REACTIVE CAPABILITY

ECC.6.3.2.1 Reactive Capability for Type B Synchronous Power Generating Modules

ECC.6.3.2.1.1 When operating at Maximum Capacity, all Type B Synchronous Power Generating Modules must be capable of continuous operation at any points between the limits of 0.95 Power Factor lagging and 0.95 Power Factor leading at the Grid Entry Point or User System Entry Point unless otherwise agreed with The Company or relevant Network Operator. At Active Power output levels other than Maximum Capacity, all Generating Units within a Type B Synchronous Power Generating Module must be capable of continuous operation at any point between the Reactive Power capability limits identified on the HV Generator Performance Chart unless otherwise agreed with The Company or relevant Network Operator.

ECC.6.3.2.2 Reactive Capability for Type B Power Park Modules

ECC.6.3.2.2.1 When operating at Maximum Capacity all Type B Power Park Modules must be capable of continuous operation at any points between the limits of 0.95 Power Factor lagging and 0.95 Power Factor leading at the Grid Entry Point or User System Entry Point unless otherwise agreed with The Company or relevant Network Operator. At Active Power output levels other than Maximum Capacity, each Power Park Module must be capable of continuous operation at any point between the Reactive Power capability limits identified on the HV Generator Performance Chart unless otherwise agreed with The Company or Network Operator.

ECC.6.3.2.3 Reactive Capability for Type C and D Synchronous Power Generating Modules

ECC.6.3.2.3.1 In addition to meeting the requirements of ECC.6.3.2.3.2 – ECC.6.3.2.3.5, EU Generators which connect a Type C or Type D Synchronous Power Generating Module(s) to a Non Embedded Customers System or private network, may be required to meet additional reactive compensation requirements at the point of connection between the System and the Non Embedded Customer or private network where this is required for System reasons.

ECC.6.3.2.3.2 All Type C and Type D Synchronous Power Generating Modules shall be capable of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point as defined in Figure ECC.6.3.2.3 when operating at Maximum Capacity.
ECC.6.3.2.3.3 At Active Power output levels other than Maximum Capacity, all Generating Units within a Synchronous Power Generating Module must be capable of continuous operation at any point between the Reactive Power capability limit identified on the HV Generator Performance Chart at least down to the Minimum Stable Operating Level. At reduced Active Power output, Reactive Power supplied at the Grid Entry Point (or User System Entry Point if Embedded) shall correspond to the HV Generator Performance Chart of the Synchronous Power Generating Module, taking the auxiliary supplies and the Active Power and Reactive Power losses of the Generating Unit transformer or Station Transformer into account.

ECC.6.3.2.3.4 In addition, to the requirements of ECC.6.3.2.3.1 – ECC.6.3.2.3.3 the short circuit ratio of all Onshore Synchronous Generating Units with an Apparent Power rating of less than 1600MVA shall not be less than 0.5. The short circuit ratio of Onshore Synchronous Generating Units with a rated Apparent Power of 1600MVA or above shall be not less than 0.4.

ECC.6.3.2.4 Reactive Capability for Type C and D Power Park Modules, HVDC Equipment and OTSDUW Plant and Apparatus at the Interface Point

ECC.6.3.2.4.1 EU Generators or HVDC System Owners which connect an Onshore Type C or Onshore Type D Power Park Module or HVDC Equipment to a Non Embedded Customers System or private network, may be required to meet additional reactive compensation requirements at the point of connection between the System and the Non Embedded Customer or private network where this is required for System reasons.
ECC.6.3.2.4.2 All Onshore Type C Power Park Modules and Onshore Type D Power Park Modules or HVDC Converters at an HVDC Converter Station with a Grid Entry Point or User System Entry Point voltage above 33kV, or Remote End HVDC Converters with an HVDC Interface Point voltage above 33kV, or OTSUW Plant and Apparatus with an Interface Point voltage above 33kV shall be capable of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point (or Interface Point in the case of OTSUW Plant and Apparatus, or HVDC Interface Point in the case of a Remote End HVDC Converter Station) as defined in Figure ECC.6.3.2.4(a) when operating at Maximum Capacity (or Interface Point Capacity in the case of OTSUW Plant and Apparatus). In the case of Remote End HVDC Converters and DC Connected Power Park Modules, The Company in co-ordination with the Relevant Transmission Licensee may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for Offshore Power Park Modules and DC Connected Power Park Modules are defined in ECC.6.3.2.5 and ECC.6.3.2.6.

ECC.6.3.2.4.3 All Onshore Type C or Type D Power Park Modules or HVDC Converters at a HVDC Converter Station with a Grid Entry Point or User System Entry Point voltage at or below 33kV or Remote End HVDC Converter Station with an HVDC Interface Point Voltage at or below 33kV shall be capable of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point as defined in Figure ECC.6.3.2.4(b) when operating at Maximum Capacity. In the case of Remote End HVDC Converters The Company in co-ordination with the Relevant Transmission Licensee may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(b), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for Offshore Power Park Modules and DC Connected Power Park Modules are defined in ECC.6.3.2.5 and ECC.6.3.2.6.
All Type C and Type D Power Park Modules, HVDC Converters at a HVDC Converter Station including Remote End HVDC Converters or OTSDUW Plant and Apparatus, shall be capable of satisfying the Reactive Power capability requirements at the Grid Entry Point or User System Entry Point (or Interface Point Capacity in the case of OTSUW Plant and Apparatus or HVDC Interface Point in the case of Remote End HVDC Converter Stations) as defined in Figure ECC.6.3.2.4(c) when operating below Maximum Capacity. With all Plant in service, the Reactive Power limits will reduce linearly below 50% Active Power output as shown in Figure ECC.6.3.2.4(c) unless the requirement to maintain the Reactive Power limits defined at Maximum Capacity (or Interface Point Capacity in the case of OTSDUW Plant and Apparatus) under absorbing Reactive Power conditions down to 20% Active Power output has been specified by The Company. These Reactive Power limits will be reduced pro rata to the amount of Plant in service. In the case of Remote End HVDC Converters, The Company in co-ordination with the Relevant Transmission Licensee may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.4(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies. For the avoidance of doubt, the requirements for Offshore Power Park Modules and DC Connected Power Park Modules are defined in ECC.6.3.2.5 and ECC.6.3.2.6.
Reactive Capability for Offshore Synchronous Power Generating Modules, Configuration 1 AC connected Offshore Power Park Modules and Configuration 1 DC Connected Power Park Modules.

The short circuit ratio of any Offshore Synchronous Generating Units within a Synchronous Power Generating Module shall not be less than 0.5. All Offshore Synchronous Generating Units, Configuration 1 AC connected Offshore Power Park Modules or Configuration 1 DC Connected Power Park Modules must be capable of maintaining zero transfer of Reactive Power at the Offshore Grid Entry Point. The steady state tolerance on Reactive Power transfer to and from an Offshore Transmission System expressed in MVar shall be no greater than 5% of the Maximum Capacity.

For the avoidance of doubt if an EU Generator (including those in respect of DC Connected Power Park Modules) wishes to provide a Reactive Power capability in excess of the minimum requirements defined in ECC.6.3.2.5.1 then such capability (including steady state tolerance) shall be agreed between the Generator, Offshore Transmission Licensee and The Company and/or the relevant Network Operator.


All Configuration 2 AC connected Offshore Power Park Modules and Configuration 2 DC Connected Power Park Modules shall be capable of satisfying the minimum Reactive Power capability requirements at the Offshore Grid Entry Point as defined in Figure ECC.6.3.2.6(a) when operating at Maximum Capacity. The Company in co-ordination with the Relevant Transmission Licensee may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.6(a), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies.
ECC.6.3.2.6.2 All **AC Connected Configuration 2 Offshore Power Park Modules** and **Configuration 2 DC Connected Power Park Modules** shall be capable of satisfying the **Reactive Power** capability requirements at the **Offshore Grid Entry Point** as defined in Figure ECC.6.3.2.6(b) when operating below **Maximum Capacity**. With all **Plant** in service, the **Reactive Power** limits will reduce linearly below 50% **Active Power** output as shown in Figure ECC.6.3.2.6(b) unless the requirement to maintain the **Reactive Power** limits defined at **Maximum Capacity** (or **Interface Point Capacity** in the case of **OTSDUW Plant and Apparatus**) under absorbing **Reactive Power** conditions down to 20% **Active Power** output has been specified with **The Company**. These **Reactive Power** limits will be reduced pro rata to the amount of **Plant** in service. **The Company** in co-ordination with the **Relevant Transmission Licensee** may agree to alternative reactive capability requirements to those specified in Figure ECC.6.3.2.6(b), where it is demonstrated that it is uneconomic and inefficient to do so, for example in the case of new technologies or advanced control strategies.
For the avoidance of doubt if an EU Generator (including Generators in respect of DC Connected Power Park Modules referred to in ECC.6.3.2.6.2) wishes to provide a Reactive Power capability in excess of the minimum requirements defined in ECC.6.3.2.6.1 then such capability (including any steady state tolerance) shall be between the EU Generator, Offshore Transmission Licensee and The Company and/or the relevant Network Operator.

**OUTPUT POWER WITH FALLING FREQUENCY**

**ECC.6.3.3.1** Output power with falling frequency for Power Generating Modules and HVDC Equipment

**ECC.6.3.3.1.1** Each Power Generating Module and HVDC Equipment must be capable of:

(a) continuously maintaining constant Active Power output for System Frequency changes within the range 50.5 to 49.5 Hz; and

(b) (subject to the provisions of ECC.6.1.2) maintaining its Active Power output at a level not lower than the figure determined by the linear relationship shown in Figure ECC.6.3.3(a) for System Frequency changes within the range 49.5 to 47 Hz for all ambient temperatures up to and including 25°C, such that if the System Frequency drops to 47 Hz the Active Power output does not decrease by more than 5%. In the case of a CCGT Module, the above requirement shall be retained down to the Low Frequency Relay trip setting of 48.8 Hz, which reflects the first stage of the Automatic Low Frequency Demand Disconnection scheme notified to Network Operators under OC6.6.2. For System Frequency below that setting, the existing requirement shall be retained for a minimum period of 5 minutes while System Frequency remains below that setting, and special measure(s) that may be required to meet this requirement shall be kept in service during this period. After that 5 minutes period, if System Frequency remains below that setting, the special measure(s) must be discontinued if there is a materially increased risk of the Gas Turbine tripping. The need for special measure(s) is linked to the inherent Gas Turbine Active Power output reduction caused by reduced shaft speed due to falling System Frequency. Where the need for special measures is identified in order to maintain output in line with the level identified in Figure ECC.6.3.3(a) these measures should be still continued at ambient temperatures above 25°C maintaining as much of the Active Power achievable within the capability of the plant. For the avoidance of doubt, Generators in respect of Pumped Storage Plant and Electricity Storage Modules shall also be required to satisfy the requirements of OC6.6.6.
Figure ECC.6.3.3(a) Active Power Output with falling frequency for Power Generating Modules and HVDC Systems and Electricity Storage Modules when operating in an exporting mode of operation.
(c) For the avoidance of doubt, in the case of a Power Generating Module including a DC Connected Power Park Module using an Intermittent Power Source where the mechanical power input will not be constant over time, the requirement is that the Active Power output shall be independent of System Frequency under (a) above and should not drop with System Frequency by greater than the amount specified in (b) above.

(d) An HVDC System must be capable of maintaining its Active Power input (i.e. when operating in a mode analogous to Demand) from the National Electricity Transmission System (or User System in the case of an Embedded HVDC System) at a level not greater than the figure determined by the linear relationship shown in Figure ECC.6.3.3(b) for System Frequency changes within the range 49.5 to 47 Hz, such that if the System Frequency drops to 47.8 Hz the Active Power input decreases by more than 60%.
(e) In the case of an Offshore Generating Unit or Offshore Power Park Module or DC Connected Power Park Module or Remote End HVDC Converter or Transmission DC Converter, the EU Generator shall comply with the requirements of ECC.6.3.3. EU Generators should be aware that Section K of the STC places requirements on Offshore Transmission Licensees which utilise a Transmission DC Converter as part of their Offshore Transmission System to make appropriate provisions to enable EU Generators to fulfil their obligations.

(f) Transmission DC Converters and Remote End HVDC Converters shall provide a continuous signal indicating the real time frequency measured at the Interface Point to the Offshore Grid Entry Point or HVDC Interface Point for the purpose of Offshore Generators or DC Connected Power Park Modules to respond to changes in System Frequency on the Main Interconnected Transmission System. A DC Connected Power Park Module or Offshore Power Generating Module shall be capable of receiving and processing this signal within 100ms.

ECC.6.3.4  
**ACTIVE POWER OUTPUT UNDER SYSTEM VOLTAGE VARIATIONS**

ECC.6.3.4.1 At the Grid Entry Point or User System Entry Point, the Active Power output under steady state conditions of any Power Generating Module or HVDC Equipment directly connected to the National Electricity Transmission System or in the case of OTSDUW, the Active Power transfer at the Interface Point, under steady state conditions of any OTSDUW Plant and Apparatus should not be affected by voltage changes in the normal operating range specified in paragraph ECC.6.1.4 by more than the change in Active Power losses at reduced or increased voltage.

ECC.6.3.5  
**BLACK START**

ECC.6.3.5.1 Black Start is not a mandatory requirement, however EU Code Users may wish to notify The Company of their ability to provide a Black Start facility and the cost of the service. The Company will then consider whether it wishes to contract with the EU Code User for the provision of a Black Start service which would be specified via a Black Start Contract. Where an EU Code User does not offer to provide a cost for the provision of a Black Start Capability, The Company may make such a request if it considers System security to be at risk due to a lack of Black Start capability.

ECC.6.3.5.2 It is an essential requirement that the National Electricity Transmission System must incorporate a Black Start Capability. This will be achieved by agreeing a Black Start Capability at a number of strategically located Power Stations and HVDC Systems. For each Power Station or HVDC System, The Company will state in the Bilateral Agreement whether or not a Black Start Capability is required.

ECC.6.3.5.3 Where an EU Code User has entered into a Black Start Contract to provide a Black Start Capability in respect of a Type C Power Generating Module or Type D Power Generating Module (including DC Connected Power Park Modules) the following requirements shall apply.

(i) The Power-Generating Module or DC Connected Power Park Module shall be capable of starting from shutdown without any external electrical energy supply within a time frame specified by The Company in the Black Start Contract.

(ii) Each Power Generating Module or DC Connected Power Park Module shall be able to synchronise within the frequency limits defined in ECC.6.1. and, where applicable, voltage limits specified in ECC.6.1.4;

(iii) The Power Generating Module or DC Connected Power Park Module shall be capable of connecting on to an unenergised System.

(iv) The Power-Generating Module or DC Connected Power Park Module shall be capable of automatically regulating dips in voltage caused by connection of demand;

(v) The Power Generating Module or DC Connected Power Park Module shall be capable of Block Load Capability,
be capable of operating in LFSM-O and LFSM-U, as specified in ECC.6.3.7.1 and ECC.6.3.7.2

control Frequency in case of overfrequency and underfrequency within the whole Active Power output range between the Minimum Regulating Level and Maximum Capacity as well as at houseload operation levels

be capable of parallel operation of a few Power Generating Modules including DC Connected Power Park Modules within an isolated part of the Total System that is still supplying Customers, and control voltage automatically during the system restoration phase;

(vi) Power Park Modules (including DC Connected Power Park Modules) and HVDC Equipment which provide a Black Start Capability, shall also be capable of satisfying the Grid Forming Capability requirements defined in ECC.6.3.19.

ECC.6.3.5.4 Each HVDC System or Remote End HVDC Converter Station which has a Black Start Capability shall be capable of energising the busbar of an AC substation to which the another HVDC Converter Station is connected. The timeframe after shutdown of the HVDC System prior to energisation of the AC substation shall be pursuant to the terms of the Black Start Contract. The HVDC System shall be able to synchronise within the Frequency limits defined in ECC.6.1.2.1.2 and voltage limits defined in ECC.6.1.4.1 unless otherwise specified in the Black Start Contract. Wider Frequency and voltage ranges can be specified in the Black Start Contract in order to restore System security.

ECC.6.3.5.5 With regard to the capability to take part in operation of an isolated part of the Total System that is still supplying Customers:

(b) Power Generating Modules including DC Connected Power Park Modules shall be capable of taking part in island operation if specified in the Black Start Contract required by The Company and:

the Frequency limits for island operation shall be those specified in ECC.6.1.2,

the voltage limits for island operation shall be those defined in ECC.6.1.4;

(i) Power Generating Modules including DC Connected Power Park Modules shall be able to operate in Frequency Sensitive Mode during island operation, as specified in ECC.6.3.7.3. In the event of a power surplus, Power Generating Modules including DC Connected Power Park Modules shall be capable of reducing the Active Power output from a previous operating point to any new operating point within the Power Generating Module Performance Chart. Power Generating Modules including DC Connected Power Park Modules shall be capable of reducing Active Power output as much as inherently technically feasible, but to at least 55 % of Maximum Capacity;

(iii) The method for detecting a change from interconnected system operation to island operation shall be agreed between the EU Generator, The Company and the Relevant Transmission Licensee. The agreed method of detection must not rely solely on The Company, Relevant Transmission Licensee's or Network Operators switchgear position signals;

(iv) Power Generating Modules including DC Connected Power Park Modules shall be able to operate in LFSM-O and LFSM-U during island operation, as specified in ECC.6.3.7.1 and ECC.6.3.7.2;

ECC.6.3.5.6 With regard to quick re-synchronisation capability:

(b) In case of disconnection of the Power Generating Module including DC Connected Power Park Modules from the System, the Power Generating Module shall be capable of quick re-synchronisation in line with the Protection strategy agreed between The Company and/or Network Operator in co-ordination with the Relevant Transmission Licensee and the Generator;
(i) A Power Generating Module including a DC Connected Power Park Module with a minimum re-synchronisation time greater than 15 minutes after its disconnection from any external power supply must be capable of Houseload Operation from any operating point on its Power Generating Module Performance Chart. In this case, the identification of Houseload Operation must not be based solely on the Total System’s switchgear position signals;

(ii) Power Generating Modules including DC Connected Power Park Modules shall be capable of Houseload Operation, irrespective of any auxiliary connection to the Total System. The minimum operation time shall be specified by The Company, taking into consideration the specific characteristics of prime mover technology.

ECC.6.3.6 CONTROL ARRANGEMENTS

ECC.6.3.6.1 ACTIVE POWER CONTROL

ECC.6.3.6.1.1 Active Power control in respect of Power Generating Modules including DC Connected Power Park Modules

ECC.6.3.6.1.1.1 Type A Power Generating Modules shall be equipped with a logic interface (input port) in order to cease Active Power output within five seconds following receipt of a signal from The Company. The Company shall specify the requirements for such facilities, including the need for remote operation, in the Bilateral Agreement where they are necessary for System reasons.

ECC.6.3.6.1.1.2 Type B Power Generating Modules shall be equipped with an interface (input port) in order to be able to reduce Active Power output following receipt of a signal from The Company. The Company shall specify the requirements for such facilities, including the need for remote operation, in the Bilateral Agreement where they are necessary for System reasons.

ECC.6.3.6.1.1.3 Type C and Type D Power Generating Modules and DC Connected Power Park Modules shall be capable of adjusting the Active Power setpoint in accordance with instructions issued by The Company.

ECC.6.3.6.1.2 Active Power control in respect of HVDC Systems and Remote End HVDC Converter Stations

ECC.6.3.6.1.2.1 HVDC Systems shall be capable of adjusting the transmitted Active Power upon receipt of an instruction from The Company which shall be in accordance with the requirements of BC2.6.1.

ECC.6.3.6.1.2.2 The requirements for fast Active Power reversal (if required) shall be specified by The Company. Where Active Power reversal is specified in the Bilateral Agreement, each HVDC System and Remote End HVDC Converter Station shall be capable of operating from maximum import to maximum export in a time which is as fast as technically feasible or in a time that is no greater than 2 seconds except where a HVDC Converter Station Owner has justified to The Company that a longer reversal time is required.

ECC.6.3.6.1.2.3 Where an HVDC System connects various Control Areas or Synchronous Areas, each HVDC System or Remote End HVDC Converter Station shall be capable of responding to instructions issued by The Company under the Balancing Code to modify the transmitted Active Power for the purposes of cross-border balancing.

ECC.6.3.6.1.2.4 An HVDC System shall be capable of adjusting the ramping rate of Active Power variations within its technical capabilities in accordance with instructions issued by The Company. In case of modification of Active Power according to ECC.6.3.15 and ECC.6.3.6.1.2.2, there shall be no adjustment of ramping rate.
ECC.6.3.6.2 MODULATION OF ACTIVE POWER

ECC.6.3.6.2.1 Each Power Generating Module (including DC Connected Power Park Modules) and Onshore HVDC Converters at an Onshore HVDC Converter Station must be capable of contributing to Frequency control by continuous modulation of Active Power supplied to the National Electricity Transmission System. For the avoidance of doubt each Onshore HVDC Converter at an Onshore HVDC Converter Station and/or OTSDUW DC Converter shall provide each EU Code User in respect of its Offshore Power Stations connected to and/or using an Offshore Transmission System a continuous signal indicating the real time Frequency measured at the Transmission Interface Point. A DC Connected Power Park Module or Offshore Power Generating Module shall be capable of receiving and processing this signal within 100ms.

ECC.6.3.6.3 MODULATION OF REACTIVE POWER

ECC.6.3.6.3.1 Notwithstanding the requirements of ECC.6.3.2, each Power Generating Module or HVDC Equipment (and OTSDUW Plant and Apparatus at a Transmission Interface Point and Remote End HVDC Converter at an HVDC Interface Point) (as applicable) must be capable of contributing to voltage control by continuous changes to the Reactive Power supplied to the National Electricity Transmission System or the User System in which it is Embedded.

ECC.6.3.7 FREQUENCY RESPONSE

ECC.6.3.7.1 Limited Frequency Sensitive Mode – Overfrequency (LFSM-O)

ECC.6.3.7.1.1 Each Power Generating Module (including DC Connected Power Park Modules) and HVDC Systems shall be capable of reducing Active Power output in response to Frequency on the Total System when this rises above 50.4Hz. For the avoidance of doubt, the provision of this reduction in Active Power output is not an Ancillary Service. Such provision is known as Limited High Frequency Response. The Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems shall be capable of operating stably during LFSM-O operation. However for a Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems operating in Frequency Sensitive Mode the requirements of LFSM-O shall apply when the frequency exceeds 50.5Hz.

ECC.6.3.7.1.2 (i) The rate of change of Active Power output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of System Frequency above 50.4Hz (ie a Droop of 10%) as shown in Figure ECC.6.3.7.1 below. This would not preclude a EU Generator or HVDC System Owner from designing their Power Generating Module with a Droop of less than 10% but in all cases the Droop should be 2% or greater.

(ii) The reduction in Active Power output must be continuously and linearly proportional, as far as is practicable, to the excess of Frequency above 50.4 Hz and must be provided increasing with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in Active Power output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the Frequency increase above 50.4 Hz. The Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems shall be capable of initiating a power Frequency response with an initial delay that is as short as possible. If the delay exceeds 2 seconds the EU Generator or HVDC System Owner shall justify the variation, providing technical evidence to The Company.

(iii) The residue of the proportional reduction in Active Power output which results from automatic action of the Power Generating Module (including DC Connected Power
Park Modules) or HVDC System output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes for the time of the Frequency increase above 50.4Hz.

(iv) For the avoidance of doubt, the LFSM-O response must be reduced when the Frequency falls again and, when to a value less than 50.4Hz, as much as possible of the increase in Active Power must be achieved within 10 seconds.

(v) For Type A and Type B Power Generating Modules which are not required to have Frequency Sensitive Mode (FSM) as described in ECC.6.3.7.3 for deviations in Frequency up to 50.9Hz at least half of the proportional reduction in Active Power output must be achieved in 10 seconds of the time of the Frequency increase above 50.4Hz. For deviations in Frequency beyond 50.9Hz the measured rate of change of Active Power reduction must exceed 0.5%/sec of the initial output. The LFSM-O response must be reduced when the Frequency subsequently falls again and when to a value less than 50.4Hz, at least half the increase in Active Power must be achieved in 10 seconds. For a Frequency excursion returning from beyond 50.9Hz the measured rate of change of Active Power increase must exceed 0.5%/second.

Figure ECC.6.3.7.1 – Pr is the reference Active Power to which ΔP is related and ΔP is the change in Active Power output from the Power Generating Module (including DC Connected Power Park Modules) or HVDC System. The Power Generating Module (including DC Connected Power Park Modules or HVDC Systems) has to provide a negative Active Power output change with a droop of 10% or less based on Pr. The Power Generating Module (including DC Connected Power Park Modules or HVDC Systems) must continue to provide such a change until the Frequency has returned to or below 50.4Hz or until otherwise instructed by The Company. EU Generators in respect of Gensets and HVDC converter Station Owners in respect of an HVDC System should also be aware of the requirements in BC.3.7.2.2.

ECC.6.3.7.1.3 Each Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems which is providing Limited High Frequency Response (LFSM-O) must continue to provide it until the Frequency has returned to or below 50.4Hz or until otherwise instructed by The Company. EU Generators in respect of Gensets and HVDC converter Station Owners in respect of an HVDC System should also be aware of the requirements in BC.3.7.2.2.

ECC.6.3.7.1.4 Steady state operation below the Minimum Stable Operating Level in the case of Power Generating Modules including DC Connected Power Park Modules or Minimum Active Power Transmission Capacity in the case of HVDC Systems is not expected but if System operating conditions cause operation below the Minimum Stable Operating Level or Minimum Active Power Transmission Capacity which could give rise to operational
difficulties for the Power Generating Module including a DC Connected Power Park Module or HVDC Systems then the EU Generator or HVDC System Owner shall be able to return the output of the Power Generating Module including a DC Connected Power Park Module to an output of not less than the Minimum Stable Operating Level or HVDC System to an output of not less than the Minimum Active Power Transmission Capacity.

ECC.6.3.7.1.5 All reasonable efforts should in the event be made by the EU Generator or HVDC System Owner to avoid such tripping provided that the System Frequency is below 52Hz in accordance with the requirements of ECC.6.1.2. If the System Frequency is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the EU Generator or HVDC System Owner is required to take action to protect its Power Generating Modules including DC Connected Power Park Modules or HVDC Converter Stations.

ECC.6.3.7.2 Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)

ECC.6.3.7.2.1 Each Type C Power Generating Module and Type D Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems operating in Limited Frequency Sensitive Mode shall be capable of increasing Active Power output in response to System Frequency when this falls below 49.5Hz. For the avoidance of doubt, the provision of this increase in Active Power output is not a mandatory Ancillary Service and it is not anticipated Power Generating Modules (including DC Connected Power Park Modules) or HVDC Systems are operated in an inefficient mode to facilitate delivery of LFSM-U response, but any inherent capability (where available) should be made without undue delay. The Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems shall be capable of stable operation during LFSM-U Mode. For example, a EU Generator which is operating with no headroom (eg it is operating at maximum output or is de-loading as part of a run down sequence and has no headroom) would not be required to provide LFSM-U.

ECC.6.3.7.2.2 (i) The rate of change of Active Power output must be at a minimum a rate of 2 percent of output per 0.1 Hz deviation of System Frequency below 49.5Hz (ie a Droop of 10%) as shown in Figure ECC.6.3.7.2.2 below. This requirement only applies if the Power Generating Module has headroom and the ability to increase Active Power output. In the case of a Power Park Module or DC Connected Power Park Module the requirements of Figure ECC.6.3.7.2.2 shall be reduced pro-rata to the amount of Power Park Units in service and available to generate. For the avoidance of doubt, this would not preclude an EU Generator or HVDC System Owner from designing their Power Generating Module with a lower Droop setting, for example between 3 – 5%.

(ii) As much as possible of the proportional increase in Active Power output must result from the Frequency control device (or speed governor) action and must be achieved for Frequencies below 49.5 Hz. The Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems shall be capable of initiating a power Frequency response with minimal delay. If the delay exceeds 2 seconds the EU Generator or HVDC System Owner shall justify the delay, providing technical evidence to The Company).

(iii) The actual delivery of Active Power Frequency Response in LFSM-U mode shall take into account

The ambient conditions when the response is to be triggered

The operating conditions of the Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems in particular limitations on operation near Maximum Capacity or Maximum HVDC Active Power Transmission Capacity at low frequencies and the respective impact of ambient conditions as detailed in ECC.6.3.3.

The availability of primary energy sources.
(iv) In LFSM_U Mode, the Power Generating Module (including DC Connected Power Park Modules) and HVDC Systems, shall be capable of providing a power increase up to its Maximum Capacity or Maximum HVDC Active Power Transmission Capacity (as applicable).

![Active Power Frequency response capability of when operating in LFSM-U](image)

Figure ECC.6.3.7.2.2 – $P_{\text{ref}}$ is the reference Active Power to which $\Delta P$ is related and $\Delta P$ is the change in Active Power output from the Power Generating Module (including DC Connected Power Park Modules) or HVDC System. The Power Generating Module (including DC Connected Power Park Modules or HVDC Systems) has to provide a positive Active Power output change with a droop of 10% or less based on $P_{\text{ref}}$.

ECC.6.3.7.3 Frequency Sensitive Mode – (FSM)

ECC.6.3.7.3.1 In addition to the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 each Type C Power Generating Module and Type D Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems must be fitted with a fast acting proportional Frequency control device (or turbine speed governor) and unit load controller or equivalent control device to provide Frequency response under normal operational conditions in accordance with Balancing Code 3 (BC3). In the case of a Power Park Module including a DC Connected Power Park Module, the Frequency or speed control device(s) may be on the Power Park Module (including a DC Connected Power Park Module) or on each individual Power Park Unit (including a Power Park Unit within a DC Connected Power Park Module) or be a combination of both. The Frequency control device(s) (or speed governor(s)) must be designed and operated to the appropriate:

(i) European Specification: or

(ii) in the absence of a relevant European Specification, such other standard which is in common use within the European Community (which may include a manufacturer specification);

as at the time when the installation of which it forms part was designed or (in the case of modification or alteration to the Frequency control device (or turbine speed governor)) when the modification or alteration was designed.
The European Specification or other standard utilised in accordance with sub paragraph ECC.6.3.7.3.1 (a) (ii) will be notified to The Company by the EU Generator or HVDC System Owner:

(i) as part of the application for a Bilateral Agreement; or
(ii) as part of the application for a varied Bilateral Agreement; or
(iii) in the case of an Embedded Development, within 28 days of entry into the Embedded Development Agreement (or such later time as agreed with The Company) or
(iv) as soon as possible prior to any modification or alteration to the Frequency control device (or governor); and

ECC.6.3.7.3.2 The Frequency control device (or speed governor) in co-ordination with other control devices must control each Type C Power Generating Module and Type D Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems Active Power Output or Active Power transfer capability with stability over the entire operating range of the Power Generating Module (including DC Connected Power Park Modules) or HVDC Systems; and

ECC.6.3.7.3.3 Type C and Type D Power Generating Modules and DC Connected Power Park Modules shall also meet the following minimum requirements:

(i) capable of providing Active Power Frequency response in accordance with the performance characteristic shown in Figure 6.3.7.3.3(a) and parameters in Table 6.3.7.3.3(a)

![Figure 6.3.7.3.3(a) - Frequency Sensitive Mode capability of Power Generating Modules and DC Connected Power Park Modules](image)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal System Frequency</td>
<td>50Hz</td>
</tr>
<tr>
<td>Active Power as a percentage of Maximum Capacity</td>
<td>10%</td>
</tr>
<tr>
<td>Frequency Response Insensitivity in mHz (</td>
<td>Δf</td>
</tr>
</tbody>
</table>

Figure 6.3.7.3.3(a) – Frequency Sensitive Mode capability of Power Generating Modules and DC Connected Power Park Modules
Frequency Response Insensitivity as a percentage of nominal frequency ($\frac{\Delta f}{f_n}$) | ±0.03%
---|---
Frequency Response Deadband in mHz | 0 (mHz)
Droop (%) | 3 – 5%

Table 6.3.7.3.3(a) – Parameters for Active Power Frequency response in Frequency Sensitive Mode including the mathematical expressions in Figure 6.3.7.3.3(a).

(ii) In satisfying the performance requirements specified in ECC.6.3.7.3(i) EU Generators in respect of each Type C and Type D Power Generating Modules and DC Connected Power Park Module should be aware:

- in the case of overfrequency, the Active Power Frequency response is limited by the Minimum Regulating Level,
- in the case of underfrequency, the Active Power Frequency response is limited by the Maximum Capacity,
- the actual delivery of Active Power frequency response depends on the operating and ambient conditions of the Power Generating Module (including DC Connected Power Park Modules) when this response is triggered, in particular limitations on operation near Maximum Capacity at low Frequencies as specified in ECC.6.3.3 and available primary energy sources.

The frequency control device (or speed governor) must also be capable of being set so that it operates with an overall speed Droop of between 3 – 5%. The Frequency Response Deadband and Droop must be able to be reselected repeatedly. For the avoidance of doubt, in the case of a Power Park Module (including DC Connected Power Park Modules) the speed Droop should be equivalent of a fixed setting between 3% and 5% applied to each Power Park Unit in service.

(iii) In the event of a Frequency step change, each Type C and Type D Power Generating Module and DC Connected Power Park Module shall be capable of activating full and stable Active Power Frequency response (without undue power oscillations), in accordance with the performance characteristic shown in Figure 6.3.7.3.3(b) and parameters in Table 6.3.7.3.3(b).
Figure 6.3.7.3.3(b) **Active Power Frequency Response** capability.

### Table 6.3.7.3.3(b) – Parameters for full activation of **Active Power Frequency** response resulting from a **Frequency** step change. Table 6.3.7.3.3(b) also includes the mathematical expressions used in Figure 6.3.7.3.3(b).

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Active Power</strong> as a percentage of Maximum Capacity (frequency response range) ($\frac{</td>
<td>\Delta P_f</td>
</tr>
<tr>
<td>Maximum admissible initial delay $t_1$ for <strong>Power Generating Modules</strong> (including <strong>DC Connected Power Park Modules</strong>) with inertia unless justified as specified in ECC.6.3.7.3.3 (iv)</td>
<td>2 seconds</td>
</tr>
<tr>
<td>Maximum admissible initial delay $t_1$ for <strong>Power Generating Modules</strong> (including <strong>DC Connected Power Park Modules</strong>) which do not contribute to <strong>System</strong> inertia unless justified as specified in ECC.6.3.7.3.3 (iv)</td>
<td>1 second</td>
</tr>
<tr>
<td>Activation time $t_2$</td>
<td>10 seconds</td>
</tr>
</tbody>
</table>
(iv) The initial activation of **Active Power Primary Frequency** response shall not be unduly delayed. For **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) with inertia the delay in initial **Active Power Frequency** response shall not be greater than 2 seconds. For **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) without inertia, the delay in initial **Active Power Frequency** response shall not be greater than 1 second. If the **Generator** cannot meet this requirement they shall provide technical evidence to **The Company** demonstrating why a longer time is needed for the initial activation of **Active Power Frequency** response.

(v) In the case of **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules**) other than the **Steam Unit** within a **CCGT Module** the combined effect of the **Frequency Response Insensitivity** and **Frequency Response Deadband** of the **Frequency control device** (or speed governor) should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the **Steam Unit** within a **CCGT Module**, the **Frequency Response Deadband** should be set to an appropriate value consistent with the requirements of ECC.6.3.7.3.5(ii) and the requirements of BC3.7.2.2 for the provision of **LFSM-O** taking account of any **Frequency Response Insensitivity** of the **Frequency control device** (or speed governor).

ECC.6.3.7.3.4 **HVDC Systems** shall also meet the following minimum requirements:

(i) **HVDC Systems** shall be capable of responding to **Frequency** deviations in each connected **AC System** by adjusting their **Active Power** import or export as shown in Figure 6.3.7.3.4(a) with the corresponding parameters in Table 6.3.7.3.4(a).

![Active Power Frequency response capability of HVDC systems when operating in FSM](image)

**Figure 6.3.7.3.4(a) – Active Power frequency response capability of a HVDC System operating in Frequency Sensitive Mode (FSM).** $\Delta P$ is the change in active power output from the **HVDC System**.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Maximum Active Power Transmission Capacity (import)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Minimum Active Power Transmission Capacity (import)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Active Power Transmission Capacity (export)</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Range available for FSM</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Range available for FSM</strong></td>
<td></td>
</tr>
<tr>
<td><strong>Droop setting is 3-5% in GB area.</strong></td>
<td></td>
</tr>
<tr>
<td><strong>f (Hz)</strong></td>
<td></td>
</tr>
<tr>
<td>48.2</td>
<td>48.8</td>
</tr>
</tbody>
</table>
Table 6.3.7.3.4(a) – Parameters for Active Power Frequency response in FSM including the mathematical expressions in Figure 6.3.7.3.4.

(ii) Each HVDC System shall be capable of adjusting the Droop for both upward and downward regulation and the Active Power range over which Frequency Sensitive Mode of operation is available as defined in ECC.6.3.7.3.4.

(iii) In addition to the requirements in ECC.6.3.7.4(i) and ECC.6.3.7.4(ii) each HVDC System shall be capable of:

- delivering the response as soon as technically feasible
- delivering the response on or above the solid line in Figure 6.3.7.3.4(b) in accordance with the parameters shown in Table 6.3.7.3.4(b)
- initiating the delivery of Primary Response in no less than 0.5 seconds unless otherwise agreed with The Company. Where the initial delay time ($t_1$ – as shown in Figure 6.3.7.3.4(b)) is longer than 0.5 seconds the HVDC Converter Station Owner shall reasonably justify it to The Company.

**Table 6.3.7.3.4(a)**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Setting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency Response Deadband</td>
<td>0</td>
</tr>
<tr>
<td>Droop S1 and S2 (upward and downward regulation) where S1=S2.</td>
<td>3 – 5%</td>
</tr>
<tr>
<td>Frequency Response Insensitivity</td>
<td>±15mHz</td>
</tr>
</tbody>
</table>

**Figure 6.3.7.3.4(b)** Active Power Frequency Response capability of a HVDC System. $\Delta P$ is the change in Active Power triggered by the step change in frequency

- $t_1 = 0.5$ seconds
- $t_2 = 10$ seconds

```
\begin{align*}
\Delta P &= \frac{1}{P_{\text{max}}} \\
|\frac{\Delta P}{P_{\text{max}}}| &= 10%
\end{align*}
```
Maximum admissible time for full activation \( t_2 \), unless longer activation times are agreed with The Company | 10 seconds

Table 6.3.7.3.4(b) – Parameters for full activation of Active Power Frequency response resulting from a Frequency step change.

(iii) For HVDC Systems connecting various Synchronous Areas, each HVDC System shall be capable of adjusting the full Active Power Frequency Response when operating in Frequency Sensitive Mode at any time and for a continuous time period. In addition, the Active Power controller of each HVDC System shall not have any adverse impact on the delivery of frequency response.

ECC.6.3.7.3.5 For HVDC Systems and Type C and Type D Power Generating Modules (including DC Connected Power Park Modules), other than the Steam Unit within a CCGT Module, the combined effect of the Frequency Response Insensitivity and Frequency Response Deadband of the Frequency control device (or speed governor) should be no greater than 0.03Hz (for the avoidance of doubt, ±0.015Hz). In the case of the Steam Unit within a CCGT Module, the Frequency Response Deadband should be set to an appropriate value consistent with the requirements of ECC.6.3.7.3.5(ii) and the requirements of BC3.7.2.2 for the provision of LFSM-O taking account of any Frequency Response Insensitivity of the Frequency control device (or speed governor);

(i) With regard to disconnection due to underfrequency, EU Generators responsible for Type C and Type D Power Generating Modules (including DC Connected Power Park Modules) capable of acting as a load, including but not limited to Pumped Storage and tidal Power Generating Modules, HVDC Systems and Remote End HVDC Converter Stations, shall be capable of disconnecting their load in case of underfrequency which will be agreed with The Company. For the avoidance of doubt this requirement does not apply to station auxiliary supplies; EU Generators in respect of Type C and Type D Pumped Storage Power Generating Modules should also be aware of the requirements in OC.6.6.6.

(ii) Where a Type C or Type D Power Generating Module, DC Connected Power Park Module or HVDC System becomes isolated from the rest of the Total System but is still supplying Customers, the Frequency control device (or speed governor) must also be able to control System Frequency below 52Hz unless this causes the Type C or Type D Power Generating Module or DC Connected Power Park Module to operate below its Minimum Regulating Level or Minimum Active Power Transmission Capacity when it is possible that it may, as detailed in BC 3.7.3, trip after a time. For the avoidance of doubt Power Generating Modules (including DC Connected Power Park Modules) and HVDC Systems are only required to operate within the System Frequency range 47 - 52 Hz as defined in ECC.6.1.2 and for converter based technologies, the remaining island contains sufficient fault level for effective commutation;

(iii) Each Type C and Type D Power Generating Module and HVDC Systems shall have the facility to modify the Target Frequency setting either continuously or in a maximum of 0.05Hz steps over at least the range 50 ±0.1Hz should be provided in the unit load controller or equivalent device.

ECC.6.3.7.3.6 In addition to the requirements of ECC.6.3.7.3 each Type C and Type D Power Generating Module and HVDC System shall be capable of meeting the minimum Frequency response requirement profile subject to and in accordance with the provisions of Appendix A3.

ECC.6.3.7.3.7 For the avoidance of doubt, the requirements of Appendix A3 do not apply to Type A and Type B Power Generating Modules.
ECC.6.3.8 EXCITATION AND VOLTAGE CONTROL PERFORMANCE REQUIREMENTS

ECC.6.3.8.1 Excitation Performance Requirements for Type B Synchronous Power Generating Modules

ECC.6.3.8.1.1 Each Synchronous Generating Unit within a Type B Synchronous Power Generating Module shall be equipped with a permanent automatic excitation control system that shall have the capability to provide constant terminal voltage control at a selectable setpoint without instability over the entire operating range of the Type B Synchronous Power Generating Module.

ECC.6.3.8.1.2 In addition to the requirements of ECC.6.3.8.1.1, The Company or the relevant Network Operator will specify if the control system of the Type B Synchronous Power Generating Module shall contribute to voltage control or Reactive Power control or Power Factor control at the Grid Entry Point or User System Entry Point (or other defined busbar). The performance requirements of the control system including slope (where applicable) shall be agreed between The Company and/or the relevant Network Operator and the EU Generator.

ECC.6.3.8.2 Voltage Control Requirements for Type B Power Park Modules

ECC.6.3.8.2.1 The Company or the relevant Network Operator will specify if the control system of the Type B Power Park Module shall contribute to voltage control or Reactive Power control or Power Factor control at the Grid Entry Point or User System Entry Point (or other defined busbar). The performance requirements of the control system including slope (where applicable) shall be agreed between The Company and/or the relevant Network Operator and the EU Generator.

ECC.6.3.8.3 Excitation Performance Requirements for Type C and Type D Onshore Synchronous Power Generating Modules

ECC.6.3.8.3.1 Each Synchronous Generating Unit within a Type C and Type D Onshore Synchronous Power Generating Modules shall be equipped with a permanent automatic excitation control system that shall have the capability to provide constant terminal voltage control at a selectable setpoint without instability over the entire operating range of the Synchronous Power Generating Module.

ECC.6.3.8.3.2 The requirements for excitation control facilities are specified in ECC.A.6. Any site specific requirements shall be specified by The Company or the relevant Network Operator.

ECC.6.3.8.3.3 Unless otherwise required for testing in accordance with OC5.A.2, the automatic excitation control system of an Onshore Synchronous Power Generating Module shall always be operated such that it controls the Onshore Synchronous Generating Unit terminal voltage to a value that is

- equal to its rated value: or
- only where provisions have been made in the Bilateral Agreement, greater than its rated value.

ECC.6.3.8.3.4 In particular, other control facilities including constant Reactive Power output control modes and constant Power Factor control modes (but excluding VAR limiters) are not required. However if present in the excitation or voltage control system they will be disabled unless otherwise agreed with The Company or the relevant Network Operator. Operation of such control facilities will be in accordance with the provisions contained in BC2.

ECC.6.3.8.3.5 The excitation performance requirements for Offshore Synchronous Power Generating Modules with an Offshore Grid Entry Point shall be specified by The Company.

ECC.6.3.8.4 Voltage Control Performance Requirements for Type C and Type D Onshore Power Park Modules, Onshore HVDC Converters and OTSUW Plant and Apparatus at the Interface Point
Each Type C and Type D Onshore Power Park Module, Onshore HVDC Converter and OTSDUW Plant and Apparatus shall be fitted with a continuously acting automatic control system to provide control of the voltage at the Grid Entry Point or User System Entry Point (or Interface Point in the case of OTSDUW Plant and Apparatus) without instability over the entire operating range of the Onshore Power Park Module, or Onshore HVDC Converter or OTSDUW Plant and Apparatus. Any Plant or Apparatus used in the provisions of such voltage control within an Onshore Power Park Module may be located at the Power Park Unit terminals, an appropriate intermediate busbar or the Grid Entry Point or User System Entry Point. In the case of an Onshore HVDC Converter at a HVDC Converter Station any Plant or Apparatus used in the provisions of such voltage control may be located at any point within the User’s Plant and Apparatus including the Grid Entry Point or User System Entry Point. OTSDUW Plant and Apparatus used in the provision of such voltage control may be located at the Offshore Grid Entry Point an appropriate intermediate busbar or at the Interface Point. When operating below 20% Maximum Capacity the automatic control system may continue to provide voltage control using any available reactive capability. If voltage control is not being provided, the automatic control system shall be designed to ensure a smooth transition between the shaded area below 20% of Active Power output and the non-shaded area above 20% of Active Power output in Figure ECC.6.3.2.4(c) and Figure ECC.6.3.2.6(b) The performance requirements for a continuously acting automatic voltage control system that shall be complied with by the User in respect of Onshore Power Park Modules, Onshore HVDC Converters at an Onshore HVDC Converter Station, OTSDUW Plant and Apparatus at the Interface Point are defined in ECC.A.7.

In particular, other control facilities, including constant Reactive Power output control modes and constant Power Factor control modes (but excluding VAR limiters) are not required. However if present in the voltage control system they will be disabled unless otherwise agreed with The Company or the relevant Network Operator. Operation of such control facilities will be in accordance with the provisions contained in BC2. Where Reactive Power output control modes and constant Power Factor control modes have been fitted within the voltage control system they shall be required to satisfy the requirements of ECC.A.7.3 and ECC.A.7.4.

Excitation Control Performance requirements applicable to AC Connected Offshore Synchronous Power Generating Modules and voltage control performance requirements applicable to AC connected Offshore Power Park Modules, DC Connected Power Park Modules and Remote End HVDC Converters

A continuously acting automatic control system is required to provide control of Reactive Power (as specified in ECC.6.3.2.5 and ECC.6.3.2.6) at the Offshore Grid Entry Point (or HVDC Interface Point in the case of Configuration 1 DC Connected Power Park Modules and Remote End HVDC Converters) without instability over the entire operating range of the AC connected Offshore Synchronous Power Generating Module or Configuration 1 AC connected Offshore Power Park Module or Configuration 1 DC Connected Power Park Modules or Remote End HVDC Converter. The performance requirements for this automatic control system will be specified by The Company which would be consistent with the requirements of ECC.6.3.2.5 and ECC.6.3.2.6.

A continuously acting automatic control system is required to provide control of Reactive Power (as specified in ECC.6.3.2.8) at the Offshore Grid Entry Point (or HVDC Interface Point in the case of Configuration 2 DC Connected Power Park Modules) without instability over the entire operating range of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Modules, otherwise the requirements of ECC.6.3.2.6 shall apply. The performance requirements for this automatic control system are specified in ECC.A.8

In addition to ECC.6.3.8.5.1 and ECC.6.3.8.5.2 the requirements for excitation or voltage control facilities, including Power System Stabilisers, where these are necessary for system reasons, will be specified by The Company. Reference is made to on-load commissioning witnessed by The Company in BC2.11.2.
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ECC.6.3.9 STEADY STATE LOAD INACCURACIES

ECC.6.3.9.1 The standard deviation of Load error at steady state Load over a 30 minute period must not exceed 2.5 per cent of a Type C or Type D Power Generating Modules (including a DC Connected Power Park Module) Maximum Capacity. Where a Type C or Type D Power Generating Module (including a DC Connected Power Park Module) is instructed to Frequency sensitive operation, allowance will be made in determining whether there has been an error according to the governor droop characteristic registered under the PC.

For the avoidance of doubt in the case of a Power Park Module (excluding a Non-Synchronous Electricity Storage Module) an allowance will be made for the full variation of mechanical power output.

In the case of an Electricity Storage Module, an allowance will be made for the storage reserve capability of the Electricity Storage Module.

ECC.6.3.10 NEGATIVE PHASE SEQUENCE LOADINGS

ECC.6.3.10.1 In addition to meeting the conditions specified in ECC.6.1.5(b), each Synchronous Power Generating Module will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by System Back-Up Protection on the National Electricity Transmission System or User System located Onshore in which it is Embedded.

ECC.6.3.11 NEUTRAL EARTHING

ECC.6.3.11 At nominal System voltages of 110kV and above the higher voltage windings of a transformer of a Power Generating Module or HVDC Equipment or transformer resulting from OTSDUW must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph ECC.6.2.1.1 (b) will be met on the National Electricity Transmission System at nominal System voltages of 110kV and above.

ECC.6.3.12 FREQUENCY AND VOLTAGE DEVIATIONS

ECC.6.3.12.1 As stated in ECC.6.1.2, the System Frequency could rise to 52Hz or fall to 47Hz. Each Power Generating Module (including DC Connected Power Park Modules) must continue to operate within this Frequency range for at least the periods of time given in ECC.6.1.2 unless The Company has specified any requirements for combined Frequency and voltage deviations which are required to ensure the best use of technical capabilities of Power Generating Modules (including DC Connected Power Park Modules) if required to preserve or restore system security. Notwithstanding this requirement, EU Generators should also be aware of the requirements of ECC.6.3.13.

ECC.6.3.13 FREQUENCY, RATE OF CHANGE OF FREQUENCY AND VOLTAGE PROTECTION SETTING ARRANGEMENTS

ECC.6.3.13.1 EU Generators (including in respect of OTSDUW Plant and Apparatus) and HVDC System Owners will be responsible for protecting all their Power Generating Modules (and OTSDUW Plant and Apparatus) or HVDC Equipment against damage should Frequency excursions outside the range 52Hz to 47Hz ever occur. Should such excursions occur, it is up to the EU Generator or HVDC System Owner to decide whether to disconnect their Apparatus for reasons of safety of Apparatus, Plant and/or personnel.

ECC.6.3.13.2 Each Power Park Module with a Grid Forming Capability as provided for in ECC.6.3.19, when connected and synchronised to the System, is required to be capable of withstanding without tripping a rate of change of Frequency up to and including 2 Hz per second as measured over a rolling 500 milliseconds period. All other Power Generating Modules when connected and synchronised to the System, shall be capable of withstanding without tripping a rate of change of Frequency up to and including 1 Hz per second as measured over a rolling 500 milliseconds period. Voltage dips may cause localised rate of change of Frequency values in excess of 1 Hz per second (or 2Hz/s in the case of Power Park Modules with a Grid Forming Capability) for short periods, and in these cases, the requirements under
ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **Power Generating Modules** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

**ECC.6.3.13.3** Each **HVDC System** and **Remote End HVDC Converter Station** when connected and synchronised to the **System**, shall be capable of withstanding without tripping a rate of change of **Frequency** up to and including ±2.5Hz per second as measured over the previous 1 second period. Voltage dips may cause localised rate of change of **Frequency** values in excess of ±2.5 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **HVDC Systems** and **Remote End HVDC Converter Stations** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

**ECC.6.3.13.4** Each **DC Connected Power Park Module** when connected to the **System**, shall be capable of withstanding without tripping a rate of change of **Frequency** up to and including ±2.0Hz per second as measured over the previous 1 second period. Voltage dips may cause localised rate of change of **Frequency** values in excess of ±2.0 Hz per second for short periods, and in these cases, the requirements under ECC.6.3.15 (fault ride through) supersedes this clause. For the avoidance of doubt, this requirement relates to the capabilities of **DC Connected Power Park Modules** only and does not impose the need for rate of change of **Frequency** protection nor does it impose a specific setting for anti-islanding or loss-of-mains protection relays.

**ECC.6.3.13.5** As stated in ECC.6.1.2, the **System Frequency** could rise to 52Hz or fall to 47Hz and the **System** voltage at the **Grid Entry Point** or **User System Entry Point** could rise or fall within the values outlined in ECC.6.1.4. Each **Type C** and **Type D Power Generating Module** (including **DC Connected Power Park Modules**) or any constituent element must continue to operate within this **Frequency** range for at least the periods of time given in ECC.6.1.2 and **voltage range** as defined in ECC.6.1.4 unless **The Company** has agreed to any simultaneous overvoltage and underfrequency relays and/or simultaneous undervoltage and over frequency relays which will trip such **Power Generating Module** (including **DC Connected Power Park Modules**), and any constituent element within this **Frequency** or voltage range. In the case of **Grid Forming Plant**, **Grid Forming Plant Owners** are also required to satisfy the **System Frequency** and **System** voltage requirements as defined in ECC.6.3.19.

**ECC.6.3.14** FAST START CAPABILITY

**ECC.6.3.14.1** It may be agreed in the **Bilateral Agreement** that a **Genset** shall have a **Fast-Start Capability**. Such Gensets may be used for **Operating Reserve** and their **Start-Up** may be initiated by **Frequency**-level relays with settings in the range 49Hz to 50Hz as specified pursuant to **OC2**.

**ECC.6.3.15** FAULT RIDE THROUGH

**ECC.6.3.15.1** General **Fault Ride Through** requirements, principles and concepts applicable to **Type B**, **Type C** and **Type D Power Generating Modules** and **OTSDUW Plant and Apparatus** subject to faults up to 140ms in duration

**ECC.6.3.15.1.1** ECC.6.3.15.1 – ECC.6.3.15.8 section sets out the **Fault Ride Through** requirements on **Type B**, **Type C** and **Type D Power Generating Modules**, **OTSDUW Plant and Apparatus** and **HVDC Equipment** that shall apply in the event of a fault lasting up to 140ms in duration.
Each Power Generating Module, Power Park Module, HVDC Equipment and OTSDUW Plant and Apparatus is required to remain connected and stable for any balanced and unbalanced fault where the voltage at the Grid Entry Point or User System Entry Point or (HVDC Interface Point in the case of Remote End DC Converter Stations or Interface Point in the case of OTSDUW Plant and Apparatus) remains on or above the heavy black line defined in sections ECC.6.3.15.2 – ECC.6.3.15.7 below.

The voltage against time curves defined in ECC.6.3.15.2 – ECC.6.3.15.7 expresses the lower limit (expressed as the ratio of its actual value and its reference 1pu) of the actual course of the phase to phase voltage (or phase to earth voltage in the case of asymmetrical/unbalanced faults) on the System voltage level at the Grid Entry Point or User System Entry Point (or HVDC Interface Point in the case of Remote End HVDC Converter Stations or Interface Point in the case of OTSDUW Plant and Apparatus) during a symmetrical or asymmetrical/unbalanced fault, as a function of time before, during and after the fault.

Voltage against time curve and parameters applicable to Type B Synchronous Power Generating Modules

Figure ECC.6.3.15.2 - Voltage against time curve applicable to Type B Synchronous Power Generating Modules

<table>
<thead>
<tr>
<th>Voltage parameters (pu)</th>
<th>Time parameters (seconds)</th>
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<tbody>
<tr>
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Table ECC.6.3.15.2 Voltage against time parameters applicable to Type B Synchronous Power Generating Modules

Voltage against time curve and parameters applicable to Type C and D Synchronous Power Generating Modules connected below 110kV
Figure ECC.6.3.15.3 - Voltage against time curve applicable to **Type C and D Synchronous Power Generating Modules** connected below 110kV

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<tr>
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</thead>
<tbody>
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Table ECC.6.3.15.3 Voltage against time parameters applicable to **Type C and D Synchronous Power Generating Modules** connected below 110kV

ECC.6.3.15.4 Voltage against time curve and parameters applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

Figure ECC.6.3.15.4 - Voltage against time curve applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

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<tr>
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</tr>
<tr>
<td>$t_{rec3}$</td>
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</table>
Table ECC.6.3.15.4 Voltage against time parameters applicable to **Type D Synchronous Power Generating Modules** connected at or above 110kV

ECC.6.3.15.5 **Voltage against time curve and parameters applicable to Type B, C and D Power Park Modules** connected below 110kV

Table ECC.6.3.15.5 Voltage against time parameters applicable to **Type B, C and D Power Park Modules** connected below 110kV

<table>
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<tr>
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<td>Urec2</td>
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</table>

ECC.6.3.15.6 **Voltage against time curve and parameters applicable to Type D Power Park Modules with a Grid Entry Point or User System Entry Point at or above 110kV, DC Connected Power Park Modules at the HVDC Interface Point or OTSDUW Plant and Apparatus at the Interface Point.**
Figure ECC.6.3.15.6 - Voltage against time curve applicable to **Type D Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or above 110kV, **DC Connected Power Park Modules** at the **HVDC Interface Point** or **OTSDUW Plant and Apparatus** at the **Interface Point**.

<table>
<thead>
<tr>
<th>Voltage parameters (pu)</th>
<th>Time parameters (seconds)</th>
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</thead>
<tbody>
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</tr>
<tr>
<td>Uclear</td>
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</tr>
<tr>
<td>Urec1</td>
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<tr>
<td>Urec2</td>
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</table>

Table ECC.6.3.15.6 Voltage against time parameters applicable to a **Type D Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or above 110kV, **DC Connected Power Park Modules** at the **HVDC Interface Point** or **OTSDUW Plant and Apparatus** at the **Interface Point**.

ECC.6.3.15.7 Voltage against time curve and parameters applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**

Figure ECC.6.3.15.7 - Voltage against time curve applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**

<table>
<thead>
<tr>
<th>Voltage parameters (pu)</th>
<th>Time parameters (seconds)</th>
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</thead>
<tbody>
<tr>
<td>Uret</td>
<td>0</td>
</tr>
<tr>
<td>Uclear</td>
<td>0</td>
</tr>
<tr>
<td>Urec1</td>
<td>0</td>
</tr>
<tr>
<td>Urec2</td>
<td>0.85</td>
</tr>
</tbody>
</table>

Table ECC.6.3.15.7 Voltage against time parameters applicable to **HVDC Systems** and **Remote End HVDC Converter Stations**

ECC.6.3.15.8 In addition to the requirements in ECC.6.3.15.1 – ECC.6.3.15.7:
(i) Each Type B, Type C and Type D Power Generating Module at the Grid Entry Point or User System Entry Point, HVDC Equipment (or OTSDUW Plant and Apparatus at the Interface Point) shall be capable of satisfying the above requirements when operating at Rated MW output and maximum leading Power Factor.

(ii) The Company will specify upon request by the User the pre-fault and post fault short circuit capacity (in MVA) at the Grid Entry Point or User System Entry Point (or HVDC Interface Point in the case of a remote end HVDC Converter Stations or Interface Point in the case of OTSDUW Plant and Apparatus).

(iii) The pre-fault voltage shall be taken to be 1.0pu and the post fault voltage shall not be less than 0.9pu.

(iv) To allow a User to model the Fault Ride Through performance of its Type B, Type C and/or Type D Power Generating Modules or HVDC Equipment, The Company will provide additional network data as may reasonably be required by the EU Code User to undertake such study work in accordance with PC.A.8. Alternatively, The Company may provide generic values derived from typical cases.

(v) The Company will publish fault level data under maximum and minimum demand conditions in the Electricity Ten Year Statement.

(vi) Each EU Generator (in respect of Type B, Type C, Type D Power Generating Modules and DC Connected Power Park Modules) and HVDC System Owners (in respect of HVDC Systems) shall satisfy the requirements in ECC.6.3.15.8(i) – (vii) unless the protection schemes and settings for internal electrical faults trips the Type B, Type C and Type D Power Generating Module, HVDC Equipment (or OTSDUW Plant and Apparatus) from the System. The protection schemes and settings should not jeopardise Fault Ride Through performance as specified in ECC.6.3.15.8(i) – (vii). The undervoltage protection at the Grid Entry Point or User System Entry Point (or HVDC Interface Point in the case of a Remote End HVDC Converter Stations or Interface Point in the case of OTSDUW Plant and Apparatus) shall be set by the EU Generator (or HVDC System Owner or OTSDUA in the case of OTSDUW Plant and Apparatus) according to the widest possible range unless The Company and the EU Code User have agreed to narrower settings. All protection settings associated with undervoltage protection shall be agreed between the EU Generator and/or HVDC System Owner with The Company and Relevant Transmission Licensee’s and relevant Network Operator (as applicable).

(vii) Each Type B, Type C and Type D Power Generating Module, HVDC System and OTSDUW Plant and Apparatus at the Interface Point shall be designed such that upon clearance of the fault on the Onshore Transmission System and within 0.5 seconds of restoration of the voltage at the Grid Entry Point or User System Entry Point or HVDC Interface Point in the case of a Remote End HVDC Converter Stations or Interface Point in the case of OTSDUW Plant and Apparatus to 90% of nominal voltage or greater, Active Power output (or Active Power transfer capability in the case of OTSDW Plant and Apparatus or Remote End HVDC Converter Stations) shall be restored to at least 90% of the level immediately before the fault. Once Active Power output (or Active Power transfer capability in the case of OTSDUW Plant and Apparatus or Remote End HVDC Converter Stations) has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- The total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant.
- The oscillations are adequately damped.
- In the event of power oscillations, Power Generating Modules shall retain steady state stability when operating at any point on the Power Generating Module Performance Chart.

For AC Connected Onshore and Offshore Power Park Modules comprising switched reactive compensation equipment (such as mechanically switched capacitors and reactors), such switched reactive compensation equipment shall be controlled such that it is not switched in or out of service during the fault but may act to assist in post fault voltage recovery.

ECC.6.3.15.9 General Fault Ride Through requirements for faults in excess of 140ms in duration.
ECC.6.3.15.9.1 General Fault Ride Through requirements applicable to HVDC Equipment and OTSDUW DC Converters subject to faults and voltage dips in excess of 140ms.

ECC.6.3.15.9.1.1 The requirements applicable to HVDC Equipment including OTSDUW DC Converters subject to faults and voltage disturbances at the Grid Entry Point or User System Entry Point or Interface Point or HVDC Interface Point, including Active Power transfer capability shall be specified in the Bilateral Agreement.

ECC.6.3.15.9.2 Fault Ride Through requirements for Type C and Type D Synchronous Power Generating Modules and Type C and Type D Power Park Modules and OTSDUW Plant and Apparatus subject to faults and voltage disturbances on the Onshore Transmission System in excess of 140ms.

ECC.6.3.15.9.2.1 The Fault Ride Through requirements for Type C and Type D Synchronous Power Generating Modules subject to faults and voltage disturbances on the Onshore Transmission System in excess of 140ms are defined in ECC.6.3.15.9.2.1(a) and the Fault Ride Through Requirements for Type C and Type D Power Park Modules and OTSDUW Plant and Apparatus subject to faults and voltage disturbances on the Onshore Transmission System greater than 140ms in duration are defined in ECC.6.3.15.9.2.1(b).

(a) Requirements applicable to Synchronous Power Generating Modules subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

In addition to the requirements of ECC.6.3.15.1 – ECC.6.3.15.8 each Synchronous Power Generating Module shall:

(i) remain transiently stable and connected to the System without tripping of any Synchronous Power Generating Module for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure ECC.6.3.15.9(a) Appendix 4 and Figures EA.4.3.2(a), (b) and (c) provide an explanation and illustrations of Figure ECC.6.3.15.9(a); and,

Figure ECC.6.3.15.9(a)
(ii) provide Active Power output at the Grid Entry Point, during Supergrid Voltage dips on the Onshore Transmission System as described in Figure ECC.6.3.15.9(a), at least in proportion to the retained balanced voltage at the Onshore Grid Entry Point (for Onshore Synchronous Power Generating Modules) or Interface Point (for Offshore Synchronous Power Generating Modules) (or the retained balanced voltage at the User System Entry Point if Embedded) and shall generate maximum reactive current (where the voltage at the Grid Entry Point is outside the limits specified in ECC.6.1.4) without exceeding the transient rating limits of the Synchronous Power Generating Module and,

(iii) restore Active Power output following Supergrid Voltage dips on the Onshore Transmission System as described in Figure ECC.6.3.15.9(a), within 1 second of restoration of the voltage to 1.0pu of the nominal voltage at the:

- Onshore Grid Entry Point for directly connected Onshore Synchronous Power Generating Modules or,
- Interface Point for Offshore Synchronous Power Generating Modules or,
- User System Entry Point for Embedded Onshore Synchronous Power Generating Modules or,
- User System Entry Point for Embedded Medium Power Stations not subject to a Bilateral Agreement which comprise Synchronous Generating Units and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore)

To at least 90% of the level available immediately before the occurrence of the dip. Once the Active Power output has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

For the avoidance of doubt a balanced Onshore Transmission System Supergrid Voltage meets the requirements of ECC.6.1.5 (b) and ECC.6.1.6.

(b) Requirements applicable to Type C and Type D Power Park Modules and OTSDUW Plant and Apparatus (excluding OTSDUW DC Converters) subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

In addition to the requirements of ECC.6.3.15.5, ECC.6.3.15.6 and ECC.6.3.15.8 (as applicable) each OTSDUW Plant and Apparatus or each Power Park Module and / or any constituent Power Park Unit, shall:

(i) remain transiently stable and connected to the System without tripping of any OTSDUW Plant and Apparatus, or Power Park Module and / or any constituent Power Park Unit, for balanced Supergrid Voltage dips and associated durations on the Onshore Transmission System (which could be at the Interface Point) anywhere on or above the heavy black line shown in Figure ECC.6.3.15.9(b). Appendix 4 and Figures EA.4.3.4 (a), (b) and (c) provide an explanation and illustrations of Figure ECC.6.3.15.9(b) ; and,
(ii) be required to satisfy the requirements of ECC.6.3.16. In the case of a Non-Synchronous Generating Unit or OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source or in the case of OTSDUW Active Power transfer capability in the time range in Figure ECC.6.3.15.9(b) an allowance shall be made for the fall in input power and the corresponding reduction of real and reactive current.

(iii) restore Active Power output (or, in the case of OTSDUW, Active Power transfer capability), following Supergrid Voltage dips on the Onshore Transmission System as described in Figure ECC.6.3.15.9(b), within 1 second of restoration of the voltage to 0.9 pu of the nominal voltage at the:

- Onshore Grid Entry Point for directly connected Onshore Power Park Modules or,
- Interface Point for OTSDUW Plant and Apparatus and Offshore Power Park Modules or,
- User System Entry Point for Embedded Onshore Power Park Modules or,

User System Entry Point for Embedded Medium Power Stations which comprise Power Park Modules not subject to a Bilateral Agreement and with an Onshore User System Entry Point (irrespective of whether they are located Onshore or Offshore) to at least 90% of the level available immediately before the occurrence of the dip except in the case of a Non-Synchronous Generating Unit, OTSDUW Plant and Apparatus or Power Park Module where there has been a reduction in the Intermittent Power Source in the time range in Figure ECC.6.3.15.9(b) that restricts the Active Power output or, in the case of OTSDUW, Active Power transfer capability below this level. Once the Active Power output or, in the case of OTSDUW, Active Power transfer capability has been restored to the required level, Active Power oscillations shall be acceptable provided that:

- the total Active Energy delivered during the period of the oscillations is at least that which would have been delivered if the Active Power was constant
- the oscillations are adequately damped.

For the avoidance of doubt a balanced Onshore Transmission System Supergrid Voltage meets the requirements of ECC.6.1.5 (b) and ECC.6.1.6.
(i) In the case of a Power Park Module (excluding Non-Synchronous Electricity Storage Modules), the requirements in ECC.6.3.15.9 do not apply when the Power Park Module (excluding Non-Synchronous Electricity Storage Modules) is operating at less than 5% of its Rated MW or during very high primary energy source conditions when more than 50% of the Power Park Units in a Power Park Module have been shut down or disconnected under an emergency shutdown sequence to protect User’s Plant and Apparatus.

(ii) In addition to meeting the conditions specified in ECC.6.1.5(b) and ECC.6.1.6, each Non-Synchronous Generating Unit, OTSDUW Plant and Apparatus or Power Park Module and any constituent Power Park Unit thereof will be required to withstand, without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault, by System Back-Up Protection on the Onshore Transmission System operating at Supergrid Voltage.

(iii) Generators in respect of Type B, Type C and Type D Power Park Modules and HVDC System Owners are required to confirm to The Company, their repeated ability to operate through balanced and unbalanced faults and System disturbances each time the voltage at the Grid Entry Point or User System Entry Point falls outside the limits specified in ECC.6.1.4. Demonstration of this capability would be satisfied by EU Generators and HVDC System Owners supplying the protection settings of their plant, informing The Company of the maximum number of repeated operations that can be performed under such conditions and any limiting factors to repeated operation such as protection or thermal rating; and

(iv) Notwithstanding the requirements of ECC.6.3.15(v), Power Generating Modules shall be capable of remaining connected during single phase or three phase auto-reclosures to the National Electricity Transmission System and operating without power reduction as long as the voltage and frequency remain within the limits defined in ECC.6.1.4 and ECC.6.1.2; and

(v) For the avoidance of doubt the requirements specified in ECC.6.3.15 do not apply to Power Generating Modules connected to either an unhealthy circuit and/or islanded from the Transmission System even for delayed auto reclosure times.

(vi) To avoid unwanted island operation, Non-Synchronous Generating Units in Scotland (and those directly connected to a Scottish Offshore Transmission System), Power Park Modules in Scotland (and those directly connected to a Scottish Offshore Transmission System), or OTSDUW Plant and Apparatus with an Interface Point in Scotland shall be tripped for the following conditions:

1. Frequency above 52Hz for more than 2 seconds
2. Frequency below 47Hz for more than 2 seconds
3. Voltage as measured at the Onshore Connection Point or Onshore User System Entry Point or Offshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus is below 80% for more than 2.5 seconds

Voltage as measured at the Onshore Connection Point or Onshore User System Entry Point or Offshore Grid Entry Point or Interface Point in the case of OTSDUW Plant and Apparatus is above 120% (115% for 275kV) for more than 1 second. The times in sections (1) and (2) are maximum trip times. Shorter times may be used to protect the Non-Synchronous Generating Units, or OTSDUW Plant and Apparatus.

ECC.6.3.15.11 HVDC System Robustness

ECC.6.3.15.11.1 The HVDC System shall be capable of finding stable operation points with a minimum change in Active Power flow and voltage level, during and after any planned or unplanned change in the HVDC System or AC System to which it is connected. The Company shall specify the changes in the System conditions for which the HVDC Systems shall remain in stable operation.
ECC.6.3.15.11.2 The HVDC System owner shall ensure that the tripping or disconnection of an HVDC Converter Station, as part of any multi-terminal or embedded HVDC System, does not result in transients at the Grid Entry Point or User System Entry Point beyond the limit specified by The Company in co-ordination with the Relevant Transmission Licensee.

ECC.6.3.15.11.3 The HVDC System shall withstand transient faults on HVAC lines in the network adjacent or close to the HVDC System, and shall not cause any of the equipment in the HVDC System to disconnect from the network due to autoreclosure of lines in the System.

ECC.6.3.15.11.4 The HVDC System Owner shall provide information to The Company on the resilience of the HVDC System to AC System disturbances.

ECC.6.3.16 FAST FAULT CURRENT INJECTION

ECC.6.3.16.1 General Fast Fault Current injection, principles and concepts applicable to Type B, Type C and Type D Power Park Modules and HVDC Equipment

ECC.6.3.16.1.1 In addition to the requirements of ECC.6.1.4, ECC.6.3.2, ECC.6.3.8 and ECC.A.7, each Type B, Type C and Type D Power Park Module or each Power Park Unit within a Type B, Type C and Type D Power Park Module or HVDC Equipment shall be required to satisfy the following requirements unless operating in a Grid Forming Capability mode in which case the requirements of ECC.6.3.19 shall apply instead. For the purposes of this requirement, current and voltage are assumed to be positive phase sequence values.

ECC.6.3.16.1.2 For any balanced fault which results in the positive phase sequence voltage falling below the voltage levels specified in ECC.6.1.4 at the Grid Entry Point or User System Entry Point (if Embedded), each Type B, Type C and Type D Power Park Module or each Power Park Unit within a Type B, Type C and Type D Power Park Module or HVDC Equipment shall, as a minimum (unless an alternative type registered solution has otherwise been agreed with The Company), be required to inject a reactive current above the heavy black line shown in Figure ECC.16.3.16(a)

![Figure ECC.6.3.16(a)](image-url)
ECC.6.3.16.1.3 Figure ECC.6.3.16(a) defines the reactive current ($I_R$) to be supplied under a faulted condition which shall be dependent upon the pre-fault operating condition and the retained voltage at the Grid Entry Point or User System Entry Point voltage. For the avoidance of doubt, each Power Park Module (and any constituent element thereof) or HVDC Equipment, shall be required to inject a reactive current ($I_n$) which shall be not less than its pre-fault reactive current and which shall as a minimum increase with the fall in the retained voltage each time the voltage at the Grid Entry Point or User System Entry Point (if Embedded) falls below 0.9pu whilst ensuring the overall rating of the Power Park Module (or constituent element thereof) or HVDC Equipment shall not be exceeded.

ECC.6.3.16.1.4 In addition to the requirements of ECC.6.3.16.1.2 and ECC.6.3.16.1.3, each Type B, Type C and Type D Power Park Module or each Power Park Unit within a Type B, Type C and Type D Power Park Module or HVDC Equipment shall be required to inject reactive current above the shaded area shown in Figure ECC.6.3.16(b) and Figure ECC.6.3.16(c) which illustrates how the reactive current shall be injected over time from fault inception in which the value of $I_R$ is determined from Figure ECC.6.3.16(a). In figures ECC.6.3.16(b) and ECC.6.3.16(c) $\Delta I_n$ is the value of the reactive current ($I_n$) less the prefault current. In this context fault inception is taken to be when the voltage at the Grid Entry Point or User System Entry Point falls below 0.9pu.

Figure ECC.6.3.16(b)
ECC.6.3.16.1.5 The injected reactive current ($I_R$) shall be above the shaded area shown in Figure ECC.6.3.16(b) and Figure ECC.6.3.16(c) with priority being given to reactive current injection with any residual capability being supplied as active current. Under any faulted condition, where the voltage falls outside the limits specified in ECC.6.1.4, there would be no requirement for each Power Park Module or constituent Power Park Unit or HVDC Equipment to exceed its transient or steady state rating of 1.0pu as defined in ECC.6.3.16.1.

ECC.6.3.16.1.6 For any planned or switching events (as outlined in ECC.6.1.7 of the Grid Code) or unplanned events which results in temporary power frequency over voltages (TOV’s), each Type B, Type C and Type D Power Generating Module or each Power Park Unit within a Type B, Type C or Type D Power Park Module or HVDC Equipment will be required to satisfy the transient overvoltage limits specified in the Bilateral Agreement.

ECC.6.3.16.1.7 For the purposes of this requirement, the maximum rated current is taken to be the maximum current each Power Park Module (or the sum of the constituent Power Park Units which are connected to the System at the Grid Entry Point or User System Entry Point) or HVDC Converter is capable of supplying. In the case of a Power Park Module this would be the maximum current at the Grid Entry Point (or User System Entry Point if Embedded) when the Power Park Module is operating at rated Active Power and rated Reactive Power (as required under ECC.6.3.2) whilst operating over the nominal voltage range as required under ECC.6.1.4 at the Grid Entry Point (or User System Entry Point if Embedded). In the case of a Power Park Unit forming part of a Type B, Type C and Type D Power Park Module, the maximum rated current expected would be the maximum current supplied from each constituent Power Park Unit when the Power Park Module is operating at rated Active Power and rated Reactive Power over the nominal voltage operating range as defined in ECC.6.1.4 less the contribution from the reactive compensation equipment.

For example, in the case of a 100MW Power Park Module (consisting of 50 x 2MW Power Park Units and +10MVAr reactive compensation equipment) the Rated Active Power at the Grid Entry Point (or User System Entry Point if Embedded) would be taken as 100MW and the rated Reactive Power at the Grid Entry Point or (User System Entry Point if Embedded) would be taken as 32.8MVAr (ie Rated MW output operating at 0.95 Power Factor lead or 0.95 Power Factor lag as required under ECC.6.3.2.4). In this example, the maximum rating of each constituent Power Park Unit is obtained when the Power Park Module is operating at 100MW, and +32.8MVAr less 10MVAr equal to 22.8MVAr or -32.8MVAr (less the reactive compensation equipment component of 10MVAr (ie -22.8MVAr) when operating within the normal voltage operating range as defined under ECC.6.1.4 (allowing for any reactive compensation equipment or losses in the Power Park Module array network).
For the avoidance of doubt, the total current of 1.0pu would be assumed to be on the MVA rating of the **Power Park Module** or **HVDC Equipment** (less losses). Under all normal and abnormal conditions, the steady state or transient rating of the **Power Park Module** (or any constituent element including the **Power Park Units**) or **HVDC Equipment**, would not be required to exceed the locus shown in Figure 16.3.16(d).

![Figure ECC.16.3.16(d)](image)

**ECC.6.3.16.1.7** Each **Type B, Type C and Type D Power Park Module** or **HVDC Equipment** shall be designed to ensure a smooth transition between voltage control mode and fault ride through mode in order to prevent the risk of instability which could arise in the transition between the steady state voltage operating range as defined under ECC.6.1.4 and abnormal conditions where the retained voltage falls below 90% of nominal voltage. Such a requirement is necessary to ensure adequate performance between the pre-fault operating condition of the **Power Park Module** or **HVDC Equipment** and its subsequent behaviour under faulted conditions. **EU Generators** and **HVDC System Owners** are required to both advise and agree with **The Company** the control strategy employed to mitigate the risk of such instability.

**ECC.6.3.16.1.8** Each **Type B, Type C and Type D Power Park Module** or **HVDC Equipment** shall be designed to reduce the risk of transient over voltage levels arising following clearance of the fault and in order to mitigate the risk of any form of instability which could result. **EU Generators or HVDC System Owners** shall be permitted to block or employ other means where the anticipated transient overvoltage would otherwise exceed the maximum permitted values specified in ECC.6.1.7. Figure ECC.16.3.16(b) and Figure ECC.16.3.16(c) shows the impact of variations in fault clearance time. For main protection operating times this would not exceed 140ms. The requirements for the maximum transient overvoltage withstand capability and associated time duration, shall be agreed between the **EU Code User** and **The Company** as part of the **Bilateral Agreement**. Where the **EU Code User** is able to demonstrate to **The Company** that blocking or other control strategies are required in order to prevent the risk of transient over voltage excursions as specified in ECC.6.3.16.1.5, **EU Generators** and **HVDC System Owners** are required to both advise and agree with **The Company** the control strategy, which must also include the approach taken to de-blocking.
In addition to the requirements of ECC.6.3.15, Generators in respect of Type B, Type C and Type D Power Park Modules or each Power Park Unit within a Type B, Type C and Type D Power Park Module or DC Connected Power Park Modules and HVDC System Owners in respect of HVDC Systems are required to confirm to The Company, their repeated ability to supply Fast Fault Current to the System each time the voltage at the Grid Entry Point or User System Entry Point falls outside the limits specified in ECC.6.1.4. EU Generators and HVDC Equipment Owners should inform The Company of the maximum number of repeated operations that can be performed under such conditions and any limiting factors to repeated operation such as protection or thermal rating.

To permit additional flexibility for example from Power Park Modules made up of full converter machines, DFIG machines, induction generators or HVDC Systems or Remote End HVDC Converters, The Company will permit transient or marginal deviations below the shaded area shown in Figures ECC.16.3.16(b) or ECC.16.3.16(c) provided the injected reactive current supplied exceeds the area bound in Figure ECC.6.3.16(b) or ECC.6.3.16(c). Such agreement would be confirmed and agreed between The Company and Generator.

In the case of a Power Park Module or DC Connected Power Park Module, where it is not practical to demonstrate the compliance requirements of ECC.6.3.16.1.1 to ECC.6.3.16.1.6 at the Grid Entry Point or User System Entry Point, The Company will accept compliance of the above requirements at the Power Park Unit terminals.

For the avoidance of doubt, Generators in respect of Type C and Type D Power Park Modules and OTSDUW Plant and Apparatus are also required to satisfy the requirements of ECC.6.3.15.9.2.1(b) which specifies the requirements for fault ride through for voltage dips in excess of 140ms.

In the case of an unbalanced fault, each Type B, Type C and Type D Power Park Module or each Power Park Unit within a Type B, Type C and Type D Power Park Module or HVDC Equipment shall be required to inject reactive current ($I_R$) which shall as a minimum increase with the fall in the retained unbalanced voltage up to its maximum reactive current without exceeding the transient rating of the Power Park Module (or constituent element thereof) or HVDC Equipment.

In the case of a unbalanced fault, the Generator or HVDC System Owner shall confirm to The Company their ability to prevent transient overvoltages arising on the remaining healthy phases and the control strategy employed.

Subsynchronous Torsional Interaction Damping Capability

Subsynchronous Torsional Interaction Damping Capability

HVDC System Owners, or Generators in respect of OTSDUW DC Converters or Network Operators in the case of an Embedded HVDC Systems not subject to a Bilateral Agreement must ensure that any of their Onshore HVDC Systems or OTSDUW DC Converters will not cause a sub-synchronous resonance problem on the Total System. Each HVDC System or OTSDUW DC Converter is required to be provided with sub-synchronous resonance damping control facilities. HVDC System Owners and EU Generators in respect of OTSDUW DC Converters should also be aware of the requirements in ECC.6.1.9 and ECC.6.1.10.

Where specified in the Bilateral Agreement, each OTSDUW DC Converter is required to be provided with power oscillation damping or any other identified additional control facilities.
ECC.6.3.17.1.3 Each HVDC System shall be capable of contributing to the damping of power oscillations on the National Electricity Transmission System. The control system of the HVDC System shall not reduce the damping of power oscillations. The Company in coordination with the Relevant Transmission Licensee (as applicable) shall specify a frequency range of oscillations that the control scheme shall positively damp and the System conditions when this occurs, at least accounting for any dynamic stability assessment studies undertaken by the Relevant Transmission Licensee or The Company (as applicable) to identify the stability limits and potential stability problems on the National Electricity Transmission System. The selection of the control parameter settings shall be agreed between The Company in coordination with the Relevant Transmission Licensee and the HVDC System Owner.

ECC.6.3.17.1.4 The Company shall specify the necessary extent of SSTI studies and provide input parameters, to the extent available, related to the equipment and relevant system conditions on the National Electricity Transmission System. The SSTI studies shall be provided by the HVDC System Owner. The studies shall identify the conditions, if any, where SSTI exists and propose any necessary mitigation procedure. The responsibility for undertaking the studies in accordance with these requirements lies with the Relevant Transmission Licensee and the HVDC System Owner. All parties shall be informed of the results of the studies.

ECC.6.3.17.1.5 All parties identified by The Company as relevant to each Grid Entry Point or User System Entry Point (if Embedded), including the Relevant Transmission Licensee, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. The Company shall collect this data and, where applicable, pass it on to the party responsible for the studies in accordance with Retained EU Law (Article 10 of Commission Regulation (EU) 2016/1447). Specific information relating to the interface schedules, input/output requirements, timing and submission of any studies or data would be agreed between the User and The Company and specified (where applicable) in the Bilateral Agreement.

ECC.6.3.17.1.6 The Company in coordination with the Relevant Transmission Licensee shall assess the result of the SSTI studies. If necessary for the assessment, The Company in coordination with the Relevant Transmission Licensee may request that the HVDC System Owner perform further SSTI studies in line with this same scope and extent.

ECC.6.3.17.1.7 The Company in coordination with the Relevant Transmission Licensee may review or replicate the study. The HVDC System Owner shall provide The Company with all relevant data and models that allow such studies to be performed. Submission of this data to Relevant Transmission Licensee’s shall be in accordance with the requirements of Retained EU Law (Article 10 of Commission Regulation (EU) 2016/1447).

ECC.6.3.17.1.8 Any necessary mitigating actions identified by the studies carried out in accordance with paragraphs ECC.6.3.17.1.4 or ECC.6.3.17.1.6, and reviewed by The Company in coordination with the Relevant Transmission Licensees, shall be undertaken by the HVDC System Owner as part of the connection of the new HVDC Converter Station.

ECC.6.3.17.1.9 As part of the studies and data flow in respect of ECC.6.3.17.1 – ECC.6.3.17.8 the following data exchange would take place with the time scales being pursuant to the terms of the Bilateral Agreement.

- Information supplied by The Company and Relevant Transmission Licensees
- Studies provided by the User
- User review
- The Company review
- Changes to studies and agreed updates between The Company, the Relevant Transmission Licensee and User
- Final review

ECC.6.3.17.2 Interaction between HVDC Systems or other User’s Plant and Apparatus
ECC.6.3.17.2.1 Notwithstanding the requirements of ECC6.1.9 and ECC.6.1.10, when several HVDC Converter Stations or other User's Plant and Apparatus are within close electrical proximity, The Company may specify that a study is required, and the scope and extent of that study, to demonstrate that no adverse interaction will occur. If adverse interaction is identified, the studies shall identify possible mitigating actions to be implemented to ensure compliance with the requirements of ECC.6.1.9

ECC.6.3.17.2.2 The studies shall be carried out by the connecting HVDC System Owner with the participation of all other User's identified by The Company in coordination with Relevant Transmission Licensees as relevant to each Connection Point.

ECC.6.3.17.2.3 All User's identified by The Company as relevant to the connection, and where applicable Relevant Transmission Licensee's, shall contribute to the studies and shall provide all relevant data and models as reasonably required to meet the purposes of the studies. The Company shall collect this input and, where applicable, pass it on to the party responsible for the studies in accordance with Retained EU Law (Article 10 of Commission Regulation (EU) 2016/1447). Specific information relating to the interface schedules, input/output requirements, timing and submission of any studies or data would be agreed between the User and The Company and specified (where applicable) in the Bilateral Agreement.

ECC.6.3.17.2.4 The Company in coordination with Relevant Transmission Licensees shall assess the result of the studies based on their scope and extent as specified in accordance with ECC.6.3.17.2.1. If necessary for the assessment, The Company in coordination with the Relevant Transmission Licensee may request the HVDC System Owner to perform further studies in line with the scope and extent specified in accordance with ECC.6.3.17.2.1.

ECC.6.3.17.2.5 The Company in coordination with the Relevant Transmission Licensee may review or replicate some or all of the studies. The HVDC System Owner shall provide The Company all relevant data and models that allow such studies to be performed.

ECC.6.3.17.2.6 The EU Code User and The Company, in coordination with the Relevant Transmission Licensee, shall agree any mitigating actions identified by the studies carried out following the site specific requirements and works, including any transmission reinforcement works and/or User works required to ensure that all sub-synchronous oscillations are sufficiently damped.

ECC.6.1.17.3 Fast Recovery from DC faults

ECC.6.1.17.3.1 HVDC Systems, including DC overhead lines, shall be capable of fast recovery from transient faults within the HVDC System. Details of this capability shall be subject to the Bilateral Agreement and the protection requirements specified in ECC.6.2.2.

ECC.6.1.17.4 Maximum loss of Active Power

ECC.6.1.14.4.1 An HVDC System shall be configured in such a way that its loss of Active Power injection in the GB Synchronous Area shall be in accordance with the requirements of the SQSS.

ECC.6.3.18 SYSTEM TO GENERATOR OPERATIONAL INTERTRIPPING SCHEMES

ECC.6.3.18.1 The Company may require that a System to Generator Operational Intertripping Scheme be installed as part of a condition of the connection of the EU Generator. Scheme specific details shall be included in the relevant Bilateral Agreement and shall, include the following information:

(1) the relevant category(ies) of the scheme (referred to as Category 1 Intertripping Scheme, Category 2 Intertripping Scheme, Category 3 Intertripping Scheme and Category 4 Intertripping Scheme);

(2) the Power Generating Module to be either permanently armed or that can be instructed to be armed in accordance with BC2.8;

(3) the time within which the Power Generating Module circuit breaker(s) are to be automatically tripped;
the location to which the trip signal will be provided by The Company. Such location will be provided by The Company prior to the commissioning of the Power Generating Module.

Where applicable, the Bilateral Agreement shall include the conditions on the National Electricity Transmission System during which The Company may instruct the System to Generator Operational Intertripping Scheme to be armed and the conditions that would initiate a trip signal.

ECC.6.3.18 The time within which the Power Generating Module(s) circuit breaker(s) need to be automatically tripped is determined by the specific conditions local to the EU Generator. This ‘time to trip’ (defined as the time from provision of the trip signal by The Company to the specified location, to circuit breaker main contact opening) can typically range from 100ms to 10sec. A longer time to trip may allow the initiation of an automatic reduction in the Power Generating Module(s) output prior to the automatic tripping of the Power Generating Module(s) circuit breaker. Where applicable The Company may provide separate trip signals to allow for either a longer or shorter ‘time to trip’ to be initiated.

ECC.6.3.19 GRID FORMING CAPABILITY

ECC.6.3.19.1 In order for the National Electricity Transmission System to satisfy the stability requirements defined in the National Electricity Transmission System Security and Quality of Supply Standards, it is an essential requirement that an appropriate volume of Grid Forming Plant is available and capable of providing a Grid Forming Capability.

ECC.6.3.19.2 Grid Forming Capability is not a mandatory requirement but one which will be delivered through market arrangements, the details of which shall be published on The Company’s Website. Grid Forming Capability can be implemented by any technology including Electronic Power Converters with a GBGF-I ability, rotating Synchronous Generating Units or a combination of the two.

ECC.6.3.19.3 As noted in ECC.6.3.19.2, Grid Forming Capability is not a mandatory requirement, however where a User (be they a GB Code User or EU Code User) or Non-CUSC Party wishes to offer a Grid Forming Capability, then they will be required to ensure their Grid Forming Plant meets the following requirements.

(i) The Grid Forming Plant must fully comply with the applicable requirements of the Grid Code including but not limited to the Planning Code (PC), Connection Conditions (CC’s) or European Connection Conditions (ECC’s) (as applicable), Compliance Processes (CP’s) or European Compliance Processes (ECP’s) (as applicable), Operating Codes (OC’s), Balancing Codes (BC’s) and Data Registration Code (DRC).

(ii) Each GBGF-I shall comprise an Internal Voltage Source and reactance. For the avoidance of doubt, the reactance between the Internal Voltage Source and Grid Entry Point or User System Entry Point (if Embedded) within the Grid Forming Plant can only be made by a combination of several physical discrete reactances. This could include the reactance of the Synchronous Generating Unit or Power Park Unit or HVDC System or Electricity Storage Unit or Dynamic Reactive Compensation Equipment and the electrical Plant and Apparatus connecting the Synchronous Generating Unit or Power Park Unit or HVDC System or Electricity Storage Unit (such as a transformer) to the Grid Entry Point or User System Entry Point (if Embedded).

(iii) In addition to meeting the requirements of CC.6.3.15 or ECC.6.3.15, each Grid Forming Plant is required to remain in synchronism with the Total System and maintain a Load Angle whose value can vary between 0 and 90 degrees (π/2 radians).
(iv) When subject to a fault or disturbance, or System Frequency change, each Grid Forming Plant shall be capable of supplying Active ROCOF Response Power, Active Phase Jump Power, Active Damping Power, Active Control Based Power, Control Based Reactive Power, Voltage Jump Reactive Power and GBGF Fast Fault Current Injection.

(v) Each GBGF-I shall be capable of:

(a) Providing a symmetrical ability for importing and exporting Active ROCOF Response Power, Active Phase Jump Power, Active Damping Power and Active Control Based Power under both rising and falling System Frequency conditions. Such requirements will apply over the full System Frequency range as detailed in CC.6.1.2 and CC.6.1.3 or ECC.6.6.1.2 (as applicable). In satisfying these requirements, User’s and Non-CUSC Parties should be aware of (but not limited to) the exclusions in CC.6.3.3, CC.6.3.7 and BC3.7.2.1 (as applicable for GB Code User’s) or ECC.6.1.2, ECC.6.3.3, ECC.6.3.7 and BC3.7.2.1(b)(i) (as applicable for EU Code User’s and Non-CUSC Parties) during System Frequencies between 47Hz – 52Hz, excluding CC.6.1.3 or ECC.6.1.2.1 for a Grid Forming Plant with time limited output ratings. For the avoidance of doubt, an asymmetrical response is permissible as agreed with The Company when required to protect User’s and Non-CUSC Parties Plant and Apparatus or asymmetry in energy availability.

(b) Operating as a voltage source behind a real reactance.

(c) being designed so as not to cause any undue interactions which could cause damage to the Total System or other User’s Plant and Apparatus.

(d) include an Active Control Based Power part of the control system that can respond to changes in the Grid Forming Plant or external signals from the Total System available at the Grid Entry Point or User System Entry Point but with a bandwidth below 5 Hz to avoid AC System resonance problems.

(e) meeting the requirements of ECC.6.3.13 irrespective of being owned or operated by a GB Code User, EU Code User or Non-CUSC Party.

(f) GBGF-I with an importing capability mode of operation such as DC Converters, HVDC Systems and Electricity Storage Modules are required to have a predefined frequency response operating characteristic over the full import and export range which is contained within the envelope defined by the red and blue lines shown in Figure ECC.6.3.19.3. This characteristic shall be submitted to The Company. For the avoidance of doubt, Grid Forming Plants which are only capable of exporting Active Power to the Total System are only required to operate over the exporting power region.

Figure ECC.6.3.19.3
(vi) Each User or Non-CUSC Party shall design their GBGF-I system with an equivalent Damping Factor of between 0.2 and 5.0. It is down to the User or Non-CUSC Party to determine the Damping Factor, whose value shall be agreed with The Company. It is typical for the Damping Factor to be less than 1.0, though this will be dependent upon the parameters of the Grid Forming Plant and the equivalent System impedance at the Grid Entry Point or User System Entry Point.

The output of the Grid Forming Plant shall be designed such that following a disturbance on the System, the Active Power output and Reactive Power output shall be adequately damped. The damping shall be judged to be adequate if the corresponding Active Power response to a disturbance decays with a response that is in line with the response of second order system that has the same equivalent Damping Factor.

(vii) Each GBGF-I shall be designed so as not to interact and affect the operation, performance, safety or capability of other User’s Plant and Apparatus connected to the Total System. To achieve this requirement, each User and Non-CUSC Party shall be required to submit the data required in PC.A.5.8

ECC.6.3.19.4 In addition to the requirements of ECC.6.3.19.1 – ECC.6.3.19.3 each Grid Forming Plant shall also be capable of:

(i) satisfying the requirements of ECC.6.3.19.5.

(ii) operating at a minimum short circuit level of zero MVA at the Grid Entry Point or User System Entry Point.

(iii) providing any additional quality of supply requirements, including but not limited to reductions in the permitted frequency of Temporary Power System Over-voltage events (TOV’s) and System Frequency bandwidth limitations, as agreed with The Company. Such requirements will be pursuant to the terms of the Bilateral Agreement. For the avoidance of doubt, this requirement is in addition the minimum quality of supply requirements detailed in CC.6.1.5, CC.6.1.6 and CC.6.1.7 (as applicable) or ECC.6.1.5, ECC.6.1.6 and ECC.6.1.7 (as applicable),

ECC.6.3.19.5 GBGF Fast Fault Current Injection

ECC.6.3.19.5.1 For any balanced fault which results in the positive phase sequence voltage falling below the voltage levels specified in CC.6.1.4 or ECC.6.1.4 (as applicable) at the Grid Entry Point or User System Entry Point (if Embedded), a Grid Forming Plant shall, as a minimum be required to inject a reactive current of at least their Peak Current Rating when the voltage at the Grid Entry Point or User System Entry Point drops to zero. For intermediate retained voltages at the Grid Entry Point or User System Entry Point, the injected reactive current shall be on or above a line drawn from the bottom left hand corner of the normal voltage control operating zone (shown in the rectangular green shaded area of Figure ECC.6.3.19.5(a)) and the specified Peak Current Rating at a voltage of zero at the Grid Entry Point or User System Entry Point as shown in Figure ECC.16.3.19.5(a). Typical examples of limit lines are shown in Figure ECC.16.3.19.5(a) for a Peak Current Rating of 1.0pu where the injected reactive current must be on or above the black line and a Peak Current Rating of 1.5pu where injected reactive current must be on or above the red line.
ECC.6.3.19.5.2 Figure ECC.6.3.19.5(a) defines the reactive current to be supplied under a faulted condition which shall be dependent upon the pre-fault operating condition and the retained voltage at the Grid Entry Point or User System Entry Point voltage. For the avoidance of doubt, each Grid Forming Plant (and any constituent element thereof), shall be required to inject a reactive current which shall be not less than its pre-fault reactive current and which shall as a minimum, increase each time the voltage at the Grid Entry Point or User System Entry Point (if Embedded) falls below 0.9pu whilst ensuring the overall rating of the Grid Forming Plant (or constituent element thereof) shall not be exceeded.

ECC.6.3.19.5.3 In addition to the requirements of ECC.6.3.19.5.1 and ECC.6.3.19.5.2, each Grid Forming Plant shall be required to inject reactive current above the shaded area shown in Figure ECC.6.3.19.5(b) when the retained voltage at the Grid Entry Point or User System Entry Point falls to 0pu. Where the retained voltage at the Grid Entry Point or User System Entry Point is below 0.9pu but above 0pu (for example when significant active current is drawn by loads and/or resistive components arising from both local and remote faults or disturbances from other Plant and Apparatus connected to the Total System) the injected reactive current component shall be in accordance with Figure ECC.6.3.19.5(a).
ECC.6.3.19.5.4 The injected current shall be above the shaded area shown in Figure ECC.6.3.19.5(b) for the duration of the fault clearance time which for faults on the Transmission System cleared in Main Protection operating times shall be up to 140ms. Under any faulted condition, where the voltage falls outside the limits specified in CC.6.1.4 or ECC.6.1.4 (as applicable), there will be no requirement for each Grid Forming Plant or constituent part to exceed its transient or steady state rating as defined in Table PC.A.5.8.2.

ECC.6.3.19.5.5 For any planned or switching events (as outlined in CC.6.1.7 or ECC.6.1.7 of the Grid Code) or unplanned events which results in Temporary Power System Over Voltages (TOV’s), each Grid Forming Plant will be required to satisfy the transient overvoltage limits specified in the Bilateral Agreement.

ECC.6.3.19.5.6 For the purposes of this requirement, the maximum rated current will be the Peak Current Rating declared by the Grid Forming Plant Owner in accordance with Table PC.A.5.8.2.

ECC.6.3.19.5.7 Each Grid Forming Plant shall be designed to ensure a smooth transition between voltage control mode and Fault Ride Through mode in order to prevent the risk of instability which could arise in the transition between the steady state voltage operating range as defined under CC.6.1.4 or ECC.6.1.4 (as applicable) and abnormal conditions where the retained voltage falls below 90% of nominal voltage. Such a requirement is necessary to ensure adequate performance between the pre-fault operating condition of the Grid Forming Plant and its subsequent behaviour under faulted conditions. Grid Forming Plant Owners are required to both advise and agree with The Company the control strategy employed to mitigate the risk of such instability.

ECC.6.3.19.5.8 Each Grid Forming Plant shall be designed to reduce the risk of transient overvoltage levels arising following clearance of the fault and in order to mitigate the risk of any form of instability which could result. The requirements for the maximum transient overvoltage withstand capability and associated time duration, shall be agreed between the User or Non-CUSC Party and The Company as part of the Bilateral Agreement.

ECC.6.3.19.5.9 In addition to the requirements of CC.6.3.15 or ECC.6.3.15, each Grid Forming Plant Owner is required to confirm to The Company, their repeated ability to supply GBGF Fast Fault Current Injection to the System each time the voltage at the Grid Entry Point or User System Entry Point falls outside the limits specified in CC.6.1.4 or ECC.6.1.4 (as applicable). Grid Forming Plant Owners should inform The Company of the maximum number of repeated operations that can be performed under such conditions and any limiting factors to repeated operation such as protection or thermal rating.
ECC.6.3.19.5.10 In the case of a Power Park Module or DC Connected Power Park Module, where it is not practical to demonstrate the compliance requirements of ECC.6.3.19.5.1 to ECC.6.3.19.5.5 at the Grid Entry Point or User System Entry Point, The Company will accept compliance of the above requirements at the Power Park Unit terminals.

ECC.6.3.19.5.11 In the case of an unbalanced fault, each Grid Forming Plant, shall be required to inject current which shall as a minimum increase with the fall in the unbalanced voltage without exceeding the transient Peak Current Rating of the Grid Forming Plant (or constituent element thereof).

ECC.6.3.19.5.12 In the case of an unbalanced fault, the User or Non-CUSC Party shall confirm to The Company their ability to prevent transient overvoltages arising on the remaining healthy phases and the control strategy employed.

ECC.6.4 General Network Operator And Non-Embedded Customer Requirements
ECC.6.4.1 This part of the Grid Code describes the technical and design criteria and performance requirements for Network Operators and Non-Embedded Customers.
Neutral Earthing

ECC.6.4.2  At nominal System voltages of 132kV and above the higher voltage windings of three phase transformers and transformer banks connected to the National Electricity Transmission System must be star connected with the star point suitable for connection to earth. The earthing and lower voltage winding arrangement shall be such as to ensure that the Earth Fault Factor requirement of paragraph ECC.6.2.1.1 (b) will be met on the National Electricity Transmission System at nominal System voltages of 132kV and above.

Frequency Sensitive Relays

ECC.6.4.3  As explained under OC6, each Network Operator and Non Embedded Customer, will make arrangements that will facilitate automatic low Frequency Disconnection of Demand (based on Annual ACS Conditions). ECC.A.5.5. of Appendix E5 includes specifications of the local percentage Demand that shall be disconnected at specific frequencies. The manner in which Demand subject to low Frequency disconnection will be split into discrete MW blocks is specified in OC6.6. Technical requirements relating to Low Frequency Relays are also listed in Appendix E5.

Operational Metering

ECC.6.4.4  Where The Company can reasonably demonstrate that an Embedded Medium Power Station or Embedded HVDC System has a significant effect on the National Electricity Transmission System, it may require the Network Operator within whose System the Embedded Medium Power Station or Embedded HVDC System is situated to ensure that the operational metering equipment described in ECC.6.5.6 is installed such that The Company can receive the data referred to in ECC.6.5.6. In the case of an Embedded Medium Power Station subject to, or proposed to be subject to a Bilateral Agreement, The Company shall notify such Network Operator of the details of such installation in writing within 3 months of being notified of the application to connect under CUSC and in the case of an Embedded Medium Power Station not subject to, or not proposed to be subject to a Bilateral Agreement in writing as a Site Specific Requirement in accordance with the timescales in CUSC 6.5.5. In either case the Network Operator shall ensure that the data referred to in ECC.6.5.6 is provided to The Company.

ECC.6.4.5  Reactive Power Requirements at each EU Grid Supply Point

ECC.6.4.5.1  At each EU Grid Supply Point, Non-Embedded Customers and Network Operators who are EU Code Users shall ensure their Systems are capable of steady state operation within the Reactive Power limits as specified in ECC.6.4.5.1(a) and ECC.6.4.5.1(b). Where The Company requires a Reactive Power range which is broader than the limits defined in ECC.6.4.5.1(a) and ECC.6.4.5.1(b), this will be agreed as a reasonable requirement through joint assessment between the relevant EU Code User and The Company and justified in accordance with the requirements of ECC.6.4.5.1(c), (d), (e) and (f). For Non-Embedded Customers who are EU Code Users, the Reactive Power range at each EU Grid Supply Point, under both importing and exporting conditions, shall not exceed 48% of the larger of the Maximum Import Capability or Maximum Export Capability (0.9 Power Factor import or export of Active Power), except in situations where either technical or financial system benefits are demonstrated for Non-Embedded Customers and accepted by The Company in coordination with the Relevant Transmission Licensee.

(a) For Network Operators who are EU Code Users at each EU Grid Supply Point, the Reactive Power range shall not exceed:

(i) 48 percent (i.e. 0.9 Power Factor) of the larger of the Maximum Import Capability or Maximum Export Capability during Reactive Power import (consumption); and

(ii) 48 percent (i.e. 0.9 Power Factor) of the larger of the Maximum Import Capability or Maximum Export Capability during Reactive Power export (production);
Except in situations where either technical or financial system benefits are proved by The Company in coordination with the Relevant Transmission Licensee and the relevant Network Operator through joint analysis.

(b) The Company in co-ordination with the Relevant Transmission Licensee shall agree with the Network Operator on the scope of the analysis, which shall determine the optimal solution for Reactive Power exchange between their Systems at each EU Grid Supply Point, taking adequately into consideration the specific System characteristics, variable structure of power exchange, bidirectional flows and the Reactive Power capabilities of the Network Operator’s System. Any proposed solutions shall take the above issues into account and shall be agreed as a reasonable requirement through joint assessment between the relevant Network Operator or Non-Embedded Customer and The Company in coordination with the Relevant Transmission Licensee. In the event of a shared site between a GB Code User and EU Code User, the requirements would generally be allocated to each User on the basis of their Demand in the case of a Network Operator who is a GB Code User and applied on the basis of the Maximum Import Capability or Maximum Export Capability as specified in ECC.6.4.5.1 in the case of a Network Operator who is an EU Code User.

(c) The Company in coordination with the Relevant Transmission Licensee may specify the Reactive Power capability range at the EU Grid Supply Point in another form other than Power Factor.

(d) Notwithstanding the ability of Network Operators or Non Embedded Customers to apply for a derogation from ECC.6.4.5.1 (e), where an EU Grid Supply Point is shared between a Power Generating Module and a Non-Embedded Customers System, the Reactive Power range would be apportioned to each EU Code User at their Connection Point.

ECC.6.4.5.2 Where agreed with the Network Operator who is an EU Code User and justified though appropriate System studies, The Company may reasonably require the Network Operator not to export Reactive Power at the EU Grid Supply Point (at nominal voltage) at an Active Power flow of less than 25 % of the Maximum Import Capability. Where applicable, the Authority may require The Company in coordination with the Relevant Transmission Licensee to justify its request through a joint analysis with the relevant Network Operator and demonstrate that any such requirement is reasonable. If this requirement is not justified based on the joint analysis, The Company in coordination with the Relevant Transmission Licensee and the Network Operator shall agree on necessary requirements according to the outcomes of a joint analysis.

ECC.6.4.5.3 Notwithstanding the requirements of ECC.6.4.5.1(b) and subject to agreement between The Company and the relevant Network Operator there may be a requirement to actively control the exchange of Reactive Power at the EU Grid Supply Point for the benefit of the Total System. The Company and the relevant Network Operator shall agree on a method to carry out this control, to ensure the justified level of security of supply for both parties. Any such solution including joint study work and timelines would be agreed between The Company and the relevant Network Operator as reasonable, efficient and proportionate.

ECC.6.4.5.4 In accordance with ECC.6.4.5.3, the relevant Network Operator may require The Company to consider its Network Operator’s System for Reactive Power management. Any such requirement would need to be agreed between The Company and the relevant Network Operator and justified by The Company.

ECC.6.5 Communications Plant

ECC.6.5.1 In order to ensure control of the National Electricity Transmission System, telecommunications between Users and The Company must (including in respect of any OTSDUW Plant and Apparatus at the OTSUA Transfer Time), if required by The Company, be established in accordance with the requirements set down below.
Call in the event of an emergency. Such functionality enables Control Telephony and System Telephony. For the avoidance of doubt, System Telephony could include but shall not be limited to: an analogue or digital telephone line; a mobile telephone or an internet-based voice communication system, all of which would be connected to an appropriate public communications network.

Calls made and received over Control Telephony and System Telephony may be recorded and subsequently replayed for commercial and operational reasons.

Obligations in respect of Control Telephony and System Telephony

Where The Company requires Control Telephony, Users are required to use the Control Telephony with The Company in respect of all Connection Points with the National Electricity Transmission System and in respect of all Embedded Large Power Stations and Embedded HVDC Systems. The Company will have Control Telephony installed at the User’s Control Point where the User’s telephony equipment is not capable of providing the required facilities or is otherwise incompatible with the Transmission Control Telephony. Details of and relating to the Control Telephony required are contained in the Bilateral Agreement.

Where in The Company’s sole opinion the installation of Control Telephony is not practicable at a User’s Control Point(s), The Company shall specify in the Bilateral Agreement whether System Telephony is required. Where System Telephony is required by The Company, the User shall ensure that System Telephony is installed.

Where System Telephony is installed, Users are required to use the System Telephony with The Company in respect of those Control Point(s) for which it has been installed. Details of and relating to the System Telephony required are contained in the Bilateral Agreement.

Where Control Telephony or System Telephony is installed, routine testing of such facilities may be required by The Company (not normally more than once in any calendar month). The User and The Company shall use reasonable endeavours to agree a test programme and where The Company requests the assistance of the User in performing the agreed test programme the User shall provide such assistance. The Company requires the EU Code User to test the backup power supplies feeding its Control Telephony facilities at least once every 5 years.

Control Telephony and System Telephony shall only be used for the purposes of operational voice communication between The Company and the relevant User.

Control Telephony contains emergency calling functionality to be used for urgent operational communication only. Such functionality enables The Company and Users to utilise a priority call in the event of an emergency. The Company and Users shall only use such priority call functionality for urgent operational communications.
ECC.6.5.5.1 Detailed information on the technical interfaces and support requirements for Control Telephony is provided in the Control Telephony Electrical Standard identified in the Annex to the General Conditions. Where additional information, or information in relation to Control Telephony applicable in Scotland, is requested by Users, this will be provided, where possible, by The Company.

ECC.6.5.5.2 System Telephony shall consist of a dedicated telephone connected to an appropriate public communications network that shall be configured by the relevant User. The Company shall provide a dedicated free phone number (UK only), for the purposes of receiving incoming calls to The Company, which Users shall utilise for System Telephony. System Telephony shall only be utilised by The Company’s Control Engineer and the User’s Responsible Engineer/Operator for the purposes of operational communications.

ECC.6.5.6 Operational Metering

ECC.6.5.6.1 It is an essential requirement for The Company and Network Operators to have visibility of the real time output and status of indications of User’s Plant and Apparatus so they can control the operation of the System.

ECC.6.5.6.2 Type B, Type C and Type D Power Park Modules, HVDC Equipment, Network Operators and Non Embedded Customers are required to be capable of exchanging operational metering data with The Company and Relevant Transmission Licensees (as applicable) with time stamping. Time stamping would generally be to a sampling rate of 1 second or better unless otherwise specified by The Company in the Bilateral Agreement.

ECC.6.5.6.3 The Company in coordination with the Relevant Transmission licensee shall specify in the Bilateral Agreement the operational metering signals to be provided by the EU Generator, HVDC System Owner, Network Operator or Non-Embedded Customer. In the case of Network Operators and Non-Embedded Customers, detailed specifications relating to the operational metering standards at EU Grid Supply Points and the data required are published as Electrical Standards in the Annex to the General Conditions.

ECC.6.5.6.4 (a) The Company or the Relevant Transmission Licensee, as applicable, shall provide system control and data acquisition (SCADA) outstation interface equipment. Each EU Code User shall provide such voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the Transmission SCADA outstation interface equipment as required by The Company in accordance with the terms of the Bilateral Agreement. In the case of OTSDUW, the User shall provide such SCADA outstation interface equipment and voltage, current, Frequency, Active Power and Reactive Power measurement outputs and plant status indications and alarms to the SCADA outstation interface equipment as required by The Company in accordance with the terms of the Bilateral Agreement.

(b) For the avoidance of doubt, for Active Power and Reactive Power measurements, circuit breaker and disconnector status indications from:

(i) CCGT Modules from Type B, Type C and Type D Power Generating Modules, the outputs and status indications must each be provided to The Company on an individual CCGT Unit basis. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements from Unit Transformers and/or Station Transformers must be provided.

(ii) For Type B, Type C and Type D Power Park Modules the outputs and status indications must each be provided to The Company on an individual Power Park Module basis. In addition, where identified in the Bilateral Agreement, Active Power and Reactive Power measurements from station transformers must be provided.

(iii) In respect of OTSDUW Plant and Apparatus, the outputs and status indications must be provided to The Company for each piece of electrical equipment. In addition, where identified in the Bilateral Agreement, Active Power and Reactive
Power measurements at the Interface Point must be provided.

(c) For the avoidance of doubt, the requirements of ECC.6.5.6.4(a) in the case of a Cascade Hydro Scheme will be provided for each Generating Unit forming part of that Cascade Hydro Scheme. In the case of Embedded Generating Units forming part of a Cascade Hydro Scheme the data may be provided by means other than the SCADA outstation located at the Power Station, such as, with the agreement of the Network Operator in whose system such Embedded Generating Unit is located, from the Network Operator’s SCADA system to The Company. Details of such arrangements will be contained in the relevant Bilateral Agreements between The Company and the Generator and the Network Operator.

(d) In the case of a Power Park Module, additional energy input signals (e.g. wind speed, and wind direction) may be specified in the Bilateral Agreement. A Power Available signal will also be specified in the Bilateral Agreement. The signals would be used to establish the potential level of energy input from the Intermittent Power Source for monitoring pursuant to ECC.6.6.1 and Ancillary Services and will, in the case of a wind farm, be used to provide The Company with advanced warning of excess wind speed shutdown and to determine the level of Headroom available from Power Park Modules for the purposes of calculating response and reserve. For the avoidance of doubt, the Power Available signal would be automatically provided to The Company and represent the sum of the potential output of all available and operational Power Park Units within the Power Park Module. The refresh rate of the Power Available signal shall be specified in the Bilateral Agreement. In the case of an Electricity Storage Module, the requirement to provide a Power Available Signal when the Plant is in both an importing and exporting mode of operation would be specified in the Bilateral Agreement.

(e) In the case of an Electricity Storage Module, additional input signals (e.g. state of energy (MWhr, and system availability) may be specified in the Bilateral Agreement. A Power Available signal will also be specified in the Bilateral Agreement in accordance with the requirements of ECC.6.5.6.4(d).

ECC.6.5.6.5 In addition to the requirements of the Balancing Codes, each HVDC Converter unit of an HVDC system shall be equipped with an automatic controller capable of receiving instructions from The Company. This automatic controller shall be capable of operating the HVDC Converter units of the HVDC System in a coordinated way. The Company shall specify the automatic controller hierarchy per HVDC Converter unit.

ECC.6.5.6.6 The automatic controller of the HVDC System referred to in paragraph ECC.6.5.6.5 shall be capable of sending the following signal types to The Company (where applicable):

(a) operational metering signals, providing at least the following:

(i) start-up signals;
(ii) AC and DC voltage measurements;
(iii) AC and DC current measurements;
(iv) Active and Reactive Power measurements on the AC side;
(v) DC power measurements;
(vi) HVDC Converter unit level operation in a multi-pole type HVDC Converter;
(vii) elements and topology status; and
(viii) Frequency Sensitive Mode, Limited Frequency Sensitive Mode Overfrequency and Limited Frequency Sensitive Mode Underfrequency Active Power ranges (where applicable).

(b) alarm signals, providing at least the following:

(i) emergency blocking;
(ii) ramp blocking;
(iii) fast Active Power reversal (where applicable)

ECC.6.5.6.7 The automatic controller referred to in ECC.6.5.6.5 shall be capable of receiving the following signal types from The Company (where applicable):

(a) operational metering signals, receiving at least the following:

(i) start-up command;
(ii) Active Power setpoints;
(iii) Frequency Sensitive Mode settings;
(iv) Reactive Power, voltage or similar setpoints;
(v) Reactive Power control modes;
(vi) power oscillation damping control; and

(b) alarm signals, receiving at least the following:

(i) emergency blocking command;
(ii) ramp blocking command;
(iii) Active Power flow direction; and
(iv) fast Active Power reversal command.

ECC.6.5.6.8 With regards to operational metering signals, the resolution and refresh rate required would be 1 second or better unless otherwise agreed with The Company.

Instructor Facilities

ECC.6.5.7 The User shall accommodate Instructor Facilities provided by The Company for the receipt of operational messages relating to System conditions.

Electronic Data Communication Facilities

ECC.6.5.8 (a) All BM Participants must ensure that appropriate electronic data communication facilities are in place to permit the submission of data, as required by the Grid Code, to The Company.

(b) In addition,

(1) any User that wishes to participate in the Balancing Mechanism;

or

(2) any BM Participant in respect of its BM Units at a Power Station and the BM Participant is required to provide all Part 1 System Ancillary Services in accordance with ECC.8.1 (unless The Company has otherwise agreed)

must ensure that appropriate automatic logging devices are installed at the Control Points of its BM Units to submit data to and to receive instructions from The Company, as required by the Grid Code. For the avoidance of doubt, in the case of an Interconnector User the Control Point will be at the Control Centre of the appropriate Externally Interconnected System Operator.

(c) Detailed specifications of these required electronic facilities will be provided by The Company on request and they are listed as Electrical Standards in the Annex to the General Conditions.

Facsimile Machines

ECC.6.5.9 Each User and The Company shall provide a facsimile machine or machines:
(a) in the case of Generators, at the Control Point of each Power Station and at its Trading Point;

(b) in the case of The Company and Network Operators, at the Control Centre(s); and

(c) in the case of Non-Embedded Customers and HVDC Equipment owners at the Control Point.

Each User shall notify, prior to connection to the System of the User’s Plant and Apparatus, The Company of its or their telephone number or numbers, and will notify The Company of any changes. Prior to connection to the System of the User’s Plant and Apparatus The Company shall notify each User of the telephone number or numbers of its facsimile machine or machines and will notify any changes.

**ECC.6.5.10 Busbar Voltage**

The Relevant Transmission Licensee shall, subject as provided below, provide each Generator or HVDC System Owner at each Grid Entry Point where one of its Power Stations or HVDC Systems is connected with appropriate voltage signals to enable the Generator or HVDC System owner to obtain the necessary information to permit its Power Generating Modules (including DC Connected Power Park Modules) or HVDC System to be Synchronised to the National Electricity Transmission System. The term "voltage signal" shall mean in this context, a point of connection on (or wire or wires from) a relevant part of Transmission Plant and/or Apparatus at the Grid Entry Point, to which the Generator or HVDC System Owner, with The Company's agreement (not to be unreasonably withheld) in relation to the Plant and/or Apparatus to be attached, will be able to attach its Plant and/or Apparatus (normally a wire or wires) in order to obtain measurement outputs in relation to the busbar.

**ECC.6.5.11 Bilingual Message Facilities**

(a) A Bilingual Message Facility is the method by which the User’s Responsible Engineer/Operator, the Externally Interconnected System Operator and The Company’s Control Engineers communicate clear and unambiguous information in two languages for the purposes of control of the Total System in both normal and emergency operating conditions.

(b) A Bilingual Message Facility, where required, will provide up to two hundred pre-defined messages with up to five hundred and sixty characters each. A maximum of one minute is allowed for the transmission to, and display of, the selected message at any destination. The standard messages must be capable of being displayed at any combination of locations and can originate from any of these locations. Messages displayed in the UK will be displayed in the English language.

(c) Detailed information on a Bilingual Message Facility and suitable equipment required for individual User applications will be provided by The Company upon request.

**ECC.6.6 Monitoring**

**ECC.6.6.1 System Monitoring**

**ECC.6.6.1.1** Each Type C and Type D Power Generating Module including DC Connected Power Park Modules shall be equipped with a facility to provide fault recording and monitoring of dynamic system behaviour. These requirements are necessary to record conditions during System faults and detect poorly damped power oscillations. This facility shall record the following parameters:

- voltage,
- Active Power,
- Reactive Power, and
- Frequency.
ECC.6.6.1.2 Detailed specifications for fault recording and dynamic system monitoring equipment including triggering criteria and sample rates are listed as Electrical Standards in the General Conditions. For Dynamic System Monitoring, the specification for the communication protocol and recorded data shall also be included in the Electrical Standard.

ECC.6.6.1.3 The Company in coordination with the Relevant Transmission Licensee shall specify any requirements for Power Quality Monitoring in the Bilateral Agreement. The power quality parameters to be monitored, the communication protocols for the recorded data and the time frames for compliance shall be agreed between The Company, the Relevant Transmission Licensee and EU Generator.

ECC.6.6.1.4 HVDC Systems shall be equipped with a facility to provide fault recording and dynamic system behaviour monitoring of the following parameters for each of its HVDC Converter Stations:

(a) AC and DC voltage;
(b) AC and DC current;
(c) Active Power;
(d) Reactive Power; and
(e) Frequency.

ECC.6.6.1.5 The Company in coordination with the Relevant Transmission Licensee may specify quality of supply parameters to be complied with by the HVDC System, provided a reasonable prior notice is given.

ECC.6.6.1.6 The particulars of the fault recording equipment referred to in ECC.6.6.1.4, including analogue and digital channels, the settings, including triggering criteria and the sampling rates, shall be agreed between the HVDC System Owner and The Company in coordination with the Relevant Transmission Licensee.

ECC.6.6.1.7 All dynamic system behaviour monitoring equipment shall include an oscillation trigger, specified by The Company, in coordination with the Relevant Transmission Licensee, with the purpose of detecting poorly damped power oscillations.

ECC.6.6.1.8 The facilities for quality of supply and dynamic system behaviour monitoring shall include arrangements for the HVDC System Owner and The Company and/or Relevant Transmission Licensee to access the information electronically. The communications protocols for recorded data shall be agreed between the HVDC System Owner, The Company and the Relevant Transmission Licensee.

ECC.6.6.1.9 In order to accurately monitor the performance of a Grid Forming Plant, each Grid Forming Plant shall be equipped with a facility to accurately record the following parameters at a rate of 10ms:

- System Frequency using a nominated algorithm as defined by The Company
- The ROCOF rate using a nominated algorithm as defined by The Company based on a 500ms rolling average
- A technique for recording the Grid Phase Jump Angle by using either a nominated algorithm as defined by The Company or an algorithm that records the time period of each half cycle with a time resolution of 10 microseconds. For a 50Hz System, a 1 degree phase jump is a time period change of 55.6 microseconds.

ECC.6.6.1.10 Detailed specifications for Grid Forming Capability Plant dynamic performance including triggering criteria, sample rates, the communication protocol and recorded data shall be specified by The Company in the Bilateral Agreement.

ECC.6.6.2 Frequency Response Monitoring

ECC.6.6.2.1 Each Type C and Type D Power Generating Module including DC Connected Power Park Modules shall be fitted with equipment capable of monitoring the real time Active Power output of a Power Generating Module when operating in Frequency Sensitive Mode.
ECC.6.6.2.2 Detailed specifications of the Active Power Frequency response requirements including the communication requirements are listed as Electrical Standards in the Annex to the General Conditions.

ECC.6.6.2.3 The Company in co-ordination with the Relevant Transmission Licensee shall specify additional signals to be provided by the EU Generator by monitoring and recording devices in order to verify the performance of the Active Power Frequency response provision of participating Power Generating Modules.

ECC.6.6.3 Compliance Monitoring

ECC.6.6.3.1 For all on site monitoring by The Company of witnessed tests pursuant to the CP or OC5 or ECP the User shall provide suitable test signals as outlined in either OC5.A.1 or ECP.A.4 (as applicable).

ECC.6.6.3.2 The signals which shall be provided by the User to The Company for onsite monitoring shall be of the following resolution, unless otherwise agreed by The Company:

(i) 1 Hz for reactive range tests
(ii) 10 Hz for frequency control tests
(iii) 100 Hz for voltage control tests
(iv) 1 kHz for Grid Forming Plant signals including fast fault current measurements
(v) 100Hz for the other Grid Forming Plant tests carried out in accordance with ECC.6.6.1.9

ECC.6.6.3.3 The User will provide all relevant signals for this purpose in the form of d.c. voltages within the range -10V to +10V. In exceptional circumstances some signals may be accepted as d.c. voltages within the range -60V to +60V with prior agreement between the User and The Company. All signals shall:

(i) in the case of an Onshore Power Generating Module or Onshore HVDC Convertor Station, be suitably terminated in a single accessible location at the Generator or HVDC Converter Station owner’s site.
(ii) in the case of an Offshore Power Generating Module and OTSDUW Plant and Apparatus, be transmitted onshore without 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 be suitably terminated in a single robust location normally located at or near the onshore Interface Point of the Offshore Transmission System to which it is connected.

ECC.6.6.3.4 All signals shall be suitably scaled across the range. The following scaling would (unless The Company notify the User otherwise) be acceptable to The Company:

(a) 0MW to Maximum Capacity or Interface Point Capacity 0-8V dc
(b) Maximum leading Reactive Power to maximum lagging Reactive Power -8 to 8V dc
(c) 48 – 52Hz as -8 to 8V dc
(d) Nominal terminal or connection point voltage -10% to +10% as -8 to 8V dc

ECC.6.6.3.5 The User shall provide to The Company a 230V power supply adjacent to the signal terminal location.

ECC.7 SITE RELATED CONDITIONS

ECC.7.1 Not used.

ECC.7.2 Responsibilities For Safety
ECC.7.2.1 Any User entering and working on its Plant and/or Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site will work to the Safety Rules of the Relevant Transmission Licensee, as advised by The Company.

ECC.7.2.2 For User Sites, The Company shall procure that the Relevant Transmission Licensee entering and working on Transmission Plant and/or Apparatus on a User Site will work to the User’s Safety Rules.

ECC.7.2.3 A User may, with a minimum of six weeks notice, apply to The Company for permission to work according to that Users own Safety Rules when working on its Plant and/or Apparatus on a Transmission Site rather than those set out in ECC.7.2.1. If The Company is of the opinion that the User’s Safety Rules provide for a level of safety commensurate with those set out in ECC.7.2.1, The Company will notify the User, in writing, that, with effect from the date requested by the User, the User may use its own Safety Rules when working on its Plant and/or Apparatus on the Transmission Site. For a Transmission Site, in forming its opinion, The Company will seek the opinion of the Relevant Transmission Licensee. Until receipt of such written approval from The Company, the User will continue to use the Safety Rules as set out in ECC.7.2.1.

ECC.7.2.4 In the case of a User Site, The Company may, with a minimum of six weeks notice, apply to a User for permission for the Relevant Transmission Licensee to work according to the Relevant Transmission Licensee’s Safety Rules when working on Transmission Plant and/or Apparatus on that User Site, rather than the User’s Safety Rules. If the User is of the opinion that the Relevant Transmission Licensee’s Safety Rules, provide for a level of safety commensurate with that of that User’s Safety Rules, it will notify The Company, in writing, that, with effect from the date requested by The Company, that the Relevant Transmission Licensee may use its own Safety Rules when working on its Transmission Plant and/or Apparatus on that User Site. Until receipt of such written approval from the User, The Company shall procure that the Relevant Transmission Licensee shall continue to use the User’s Safety Rules.

ECC.7.2.5 For a Transmission Site, if The Company gives its approval for the User’s Safety Rules to apply to the User when working on its Plant and/or Apparatus, that does not imply that the User’s Safety Rules will apply to entering the Transmission Site and access to the User’s Plant and/or Apparatus on that Transmission Site. Bearing in mind the Relevant Transmission Licensee’s responsibility for the whole Transmission Site, entry and access will always be in accordance with the Relevant Transmission Licensee’s site access procedures. For a User Site, if the User gives its approval for Relevant Transmission Licensee Safety Rules to apply to the Relevant Transmission Licensee when working on its Plant and Apparatus, that does not imply that the Relevant Transmission Licensee’s Safety Rules will apply to entering the User Site, and access to the Transmission Plant and Apparatus on that User Site. Bearing in mind the User’s responsibility for the whole User Site, entry and access will always be in accordance with the User’s site access procedures.

ECC.7.2.6 For User Sites, Users shall notify The Company of any Safety Rules that apply to the Relevant Transmission Licensee’s staff working on User Sites. The Company shall procure that the Relevant Transmission Licensee shall notify Users of any Safety Rules that apply to the User’s staff working on the Transmission Site.

ECC.7.2.7 Each Site Responsibility Schedule must have recorded on it the Safety Rules which apply to each item of Plant and/or Apparatus.

ECC.7.2.8 In the case of OTSUA a User Site or Transmission Site shall, for the purposes of this ECC.7.2, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

ECC.7.3 Site Responsibility Schedules
ECC.7.3.1 In order to inform site operational staff and The Company's Control Engineers of agreed responsibilities for Plant and/or Apparatus at the operational interface, a Site Responsibility Schedule shall be produced for Connection Sites (and in the case of OTSUA, until the OTSUA Transfer Time, Interface Sites) for The Company, the Relevant Transmission Licensee and Users with whom they interface.

ECC.7.3.2 The format, principles and basic procedure to be used in the preparation of Site Responsibility Schedules are set down in Appendix 1.

ECC.7.4 Operation And Gas Zone Diagrams

Operation Diagrams

ECC.7.4.1 An Operation Diagram shall be prepared for each Connection Site at which a Connection Point exists (and in the case of OTSDUW Plant and Apparatus, by User's for each Interface Point) using, where appropriate, the graphical symbols shown in Part 1A of Appendix 2. Users should also note that the provisions of OC11 apply in certain circumstances.

ECC.7.4.2 The Operation Diagram shall include all HV Apparatus and the connections to all external circuits and incorporate numbering, nomenclature and labelling, as set out in OC11. At those Connection Sites (or in the case of OTSDUW Plant and Apparatus, Interface Points) where gas-insulated metal enclosed switchgear and/or other gas-insulated HV Apparatus is installed, those items must be depicted within an area delineated by a chain dotted line which intersects gas-zone boundaries. The nomenclature used shall conform with that used on the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, Interface Point and circuit). The Operation Diagram (and the list of technical details) is intended to provide an accurate record of the layout and circuit interconnections, ratings and numbering and nomenclature of HV Apparatus and related Plant.

ECC.7.4.3 A non-exhaustive guide to the types of HV Apparatus to be shown in the Operation Diagram is shown in Part 2 of Appendix 2, together with certain basic principles to be followed unless equivalent principles are approved by The Company.

Gas Zone Diagrams

ECC.7.4.4 A Gas Zone Diagram shall be prepared for each Connection Site at which a Connection Point (and in the case of OTSDUW Plant and Apparatus, by User's for an Interface Point) exists where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised. They shall use, where appropriate, the graphical symbols shown in Part 1B of Appendix 2.

ECC.7.4.5 The nomenclature used shall conform with that used in the relevant Connection Site and circuit (and in the case of OTSDUW Plant and Apparatus, relevant Interface Point and circuit).

ECC.7.4.6 The basic principles set out in Part 2 of Appendix 2 shall be followed in the preparation of Gas Zone Diagrams unless equivalent principles are approved by The Company.

Preparation of Operation and Gas Zone Diagrams for Users' Sites and Transmission Interface Sites

ECC.7.4.7 In the case of a User Site, the User shall prepare and submit to The Company, an Operation Diagram for all HV Apparatus on the User side of the Connection Point (and in the case of OTSDUW Plant and Apparatus, on what will be the Offshore Transmission side of the Connection Point and the Interface Point) and The Company shall provide the User with an Operation Diagram for all HV Apparatus on the Transmission side of the Connection Point (and in the case of OTSDUW Plant and Apparatus on what will be the Onshore Transmission side of the Interface Point, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement.
ECC.7.4.8 The User will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram and The Company's Operation Diagram, a composite Operation Diagram for the complete Connection Site (and in the case of OTSDUW Plant and Apparatus, Interface Point), also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.4.9 The provisions of ECC.7.4.7 and ECC.7.4.8 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

Preparation of Operation and Gas Zone Diagrams for Transmission Sites

ECC.7.4.10 In the case of a Transmission Site, the User shall prepare and submit to The Company an Operation Diagram for all HV Apparatus on the User side of the Connection Point, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.4.11 The Company will then prepare, produce and distribute, using the information submitted on the User's Operation Diagram, a composite Operation Diagram for the complete Connection Site, also in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.4.12 The provisions of ECC.7.4.10 and ECC.7.4.11 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is utilised.

ECC.7.4.13 Changes to Operation and Gas Zone Diagrams

ECC.7.4.13.1 When The Company has decided that it wishes to install new HV Apparatus or it wishes to change the existing numbering or nomenclature of Transmission HV Apparatus at a Transmission Site, The Company will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to each such User a revised Operation Diagram of that Transmission Site, incorporating the new Transmission HV Apparatus to be installed and its numbering and nomenclature or the changes, as the case may be. OC11 is also relevant to certain Apparatus.

ECC.7.4.13.2 When a User has decided that it wishes to install new HV Apparatus, or it wishes to change the existing numbering or nomenclature of its HV Apparatus at its User Site, the User will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) one month prior to the installation or change, send to The Company a revised Operation Diagram of that User Site incorporating the EU Code User HV Apparatus to be installed and its numbering and nomenclature or the changes as the case may be. OC11 is also relevant to certain Apparatus.

ECC.7.4.13.3 The provisions of ECC.7.4.13.1 and ECC.7.4.13.2 shall apply in relation to Gas Zone Diagrams where gas-insulated switchgear and/or other gas-insulated HV Apparatus is installed.

Validity

ECC.7.4.14 (a) The composite Operation Diagram prepared by The Company or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the composite Operation Diagram, a meeting shall be held at the Connection Site, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

(b) The composite Operation Diagram prepared by The Company or the User, as the case may be, will be the definitive Operation Diagram for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.
(c) An equivalent rule shall apply for Gas Zone Diagrams where they exist for a Connection Site.

ECC.7.4.15 In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this ECC.7.4, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System and references to HV Apparatus in this ECC.7.4 shall include references to HV OTSUA.

ECC.7.5 Site Common Drawings

ECC.7.5.1 Site Common Drawings will be prepared for each Connection Site (and in the case of OTSDUW, each Interface Point) and will include Connection Site (and in the case of OTSDUW, Interface Point) layout drawings, electrical layout drawings, common Protection/control drawings and common services drawings.

Preparation of Site Common Drawings for a User Site and Transmission Interface Site

ECC.7.5.2 In the case of a User Site, The Company shall prepare and submit to the User, Site Common Drawings for the Transmission side of the Connection Point (and in the case of OTSDUW Plant and Apparatus, on what will be the Offshore Transmission side of the Interface Point,) and the User shall prepare and submit to The Company, Site Common Drawings for the User side of the Connection Point (and in the case of OTSDUW, on what will be the Offshore Transmission side of the Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.5.3 The User will then prepare, produce and distribute, using the information submitted on the Transmission Site Common Drawings, Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point) in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

Preparation of Site Common Drawings for a Transmission Site

ECC.7.5.4 In the case of a Transmission Site, the User will prepare and submit to The Company Site Common Drawings for the User side of the Connection Point in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.5.5 The Company will then prepare, produce and distribute, using the information submitted in the User's Site Common Drawings, Site Common Drawings for the complete Connection Site in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement.

ECC.7.5.6 When a User becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:

(a) if it is a User Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and

(b) if it is a Transmission Site, as soon as reasonably practicable, prepare and submit to The Company revised Site Common Drawings for the User side of the Connection Point (and in the case of OTSDUW, Interface Point) and The Company will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the User's Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in the User's reasonable opinion the change can be dealt with by it notifying The Company in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

ECC.7.5.7 When The Company becomes aware that it is necessary to change any aspect of the Site Common Drawings at a Connection Site (and in the case of OTSDUW, Interface Point) it will:
(a) if it is a Transmission Site, as soon as reasonably practicable, prepare, produce and distribute revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point); and

(b) if it is a User Site, as soon as reasonably practicable, prepare and submit to the User revised Site Common Drawings for the Transmission side of the Connection Point (in the case of OTSDUW, Interface Point) and the User will then, as soon as reasonably practicable, prepare, produce and distribute, using the information submitted in the Transmission Site Common Drawings, revised Site Common Drawings for the complete Connection Site (and in the case of OTSDUW, Interface Point).

In either case, if in The Company’s reasonable opinion the change can be dealt with by it notifying the User in writing of the change and for each party to amend its copy of the Site Common Drawings (or where there is only one set, for the party holding that set to amend it), then it shall so notify and each party shall so amend. If the change gives rise to a Modification under the CUSC, the provisions of the CUSC as to timing will apply.

Validity

ECC.7.5.8 (a) The Site Common Drawings for the complete Connection Site prepared by the User or The Company, as the case may be, will be the definitive Site Common Drawings for all operational and planning activities associated with the Connection Site. If a dispute arises as to the accuracy of the Site Common Drawings, a meeting shall be held at the Site, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

(b) The Site Common Drawing prepared by The Company or the User, as the case may be, will be the definitive Site Common Drawing for all operational and planning activities associated with the Interface Point until the OTSUA Transfer Time. If a dispute arises as to the accuracy of the composite Operation Diagram prior to the OTSUA Transfer Time, a meeting shall be held at the Interface Point, as soon as reasonably practicable, between The Company and the User, to endeavour to resolve the matters in dispute.

ECC.7.5.9 In the case of OTSUA, a User Site and Transmission Site shall, for the purposes of this ECC.7.5, include a site at which there is an Interface Point until the OTSUA Transfer Time when it becomes part of the National Electricity Transmission System.

ECC.7.6 Access

ECC.7.6.1 The provisions relating to access to Transmission Sites by Users, and to Users’ Sites by Relevant Transmission Licensees, are set out in each Interface Agreement (or in the case of Interfaces Sites prior to the OTSUA Transfer Time agreements in similar form) with, the Relevant Transmission Licensee and each User.

ECC.7.6.2 In addition to those provisions, where a Transmission Site contains exposed HV conductors, unaccompanied access will only be granted to individuals holding an Authority for Access issued by the Relevant Transmission Licensee.

ECC.7.6.3 The procedure for applying for an Authority for Access is contained in the Interface Agreement.

ECC.7.7 Maintenance Standards

ECC.7.7.1 It is the User’s responsibility to ensure that all its Plant and Apparatus (including, until the OTSUA Transfer Time, any OTSUA) on a Transmission Site is tested and maintained adequately for the purpose for which it is intended, and to ensure that it does not pose a threat to the safety of any Transmission Plant, Apparatus or personnel on the Transmission Site. The Company will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus at any time.

ECC.7.7.2 For User Sites, The Company shall procure that the Relevant Transmission Licensee has a responsibility to ensure that all Transmission Plant and Apparatus on a User Site is tested and maintained adequately for the purposes for which it is intended and to ensure that it does not pose a threat to the safety of any User’s Plant, Apparatus or personnel on the User Site.
The User will have the right to inspect the test results and maintenance records relating to such Plant and Apparatus on its User Site at any time.

ECC.7.8 Site Operational Procedures

ECC.7.8.1 Where there is an interface with National Electricity Transmission System The Company and Users must make available staff to take necessary Safety Precautions and carry out operational duties as may be required to enable work/testing to be carried out and for the operation of Plant and Apparatus (including, prior to the OTSUA Transfer Time, any OTSUA) connected to the Total System.

ECC.7.9 Generators, HVDC System owners and BM Participants shall provide a Control Point.

a) In the case of EU Generators and HVDC System owners, for each Power Station or HVDC System directly connected to the National Electricity Transmission System and for each Embedded Large Power Station or Embedded HVDC System, the Control Point shall receive and act upon instructions pursuant to OC7 and BC2 at all times that Power Generating Modules at the Power Station are generating or available to generate or HVDC Systems are importing or exporting or available to do so. In the case of all BM Participants, the Control Point shall be continuously staffed except where the Bilateral Agreement specifies that compliance with BC2 is not required, in which case the Control Point shall be staffed between the hours of 0800 and 1800 each day.

b) In the case of BM Participants, the BM Participant’s Control Point shall be capable of receiving and acting upon instructions from The Company.

The Company will normally issue instructions via automatic logging devices in accordance with the requirements of ECC.6.5.8(b).

Where the BM Participant’s Plant and Apparatus does not respond to an instruction from The Company via automatic logging devices, or where it is not possible for The Company to issue the instruction via automatic logging devices, The Company shall issue the instruction by telephone.

In the case of BM Participants who own and/or operate a Power Station or HVDC System with an aggregated Registered Capacity or BM Participants with BM Units with an aggregated Demand Capacity per Control Point of less than 50MW, or, where a site is not part of a Virtual Lead Party as defined in the BSC, a Registered Capacity or Demand Capacity per site of less than 10MW

a) where this situation arises, a representative of the BM Participant is required to be available to respond to instructions from The Company via the Control Telephony or System Telephony system, as provided for in ECC.6.5.4, between the hours of 0800-1800 each day.

b) Outside the hours of 0800-1800 each day, the requirements of BC2.9.7 shall apply.

For the avoidance of doubt, BM Participants who are unable to provide Control Telephony and do not have a continuously staffed Control Point may be unable to act as a Defence Service Provider and shall be unable to act as a Restoration Service Provider or Black Start Service Provider where these require Control Telephony or a Control Point in respect of the specification of any such services falling into these categories.

ECC.8 ANCILLARY SERVICES

ECC.8.1 System Ancillary Services

The ECC contain requirements for the capability for certain Ancillary Services, which are needed for System reasons (“System Ancillary Services”). There follows a list of these System Ancillary Services, together with the paragraph number of the ECC (or other part of the Grid Code) in which the minimum capability is required or referred to. The list is divided into two categories: Part 1 lists the System Ancillary Services which
(a) **Generators** in respect of **Type C** and **Type D Power Generating Modules** (including **DC Connected Power Park Modules** and **Electricity Storage Modules**) are obliged to provide; and,

(b) **HVDC System Owners** are obliged to have the capability to supply;

(c) **Generators** in respect of **Medium Power Stations** (except **Embedded Medium Power Stations**) are obliged to provide in respect of **Reactive Power** only:

and Part 2 lists the **System Ancillary Services** which **Generators** will provide only if agreement to provide them is reached with **The Company**:

**Part 1**

(a) **Reactive Power** supplied (in accordance with ECC.6.3.2)

(b) **Frequency** Control by means of **Frequency** sensitive generation - ECC.6.3.7 and BC3.5.1

**Part 2**

(c) **Frequency** Control by means of **Fast Start** - ECC.6.3.14

(d) **Black Start Capability** - ECC.6.3.5

(e) **System to Generator Operational Intertripping**

**ECC.8.2 Commercial Ancillary Services**

Other **Ancillary Services** are also utilised by **The Company** in operating the **Total System** if these have been agreed to be provided by a **User** (or other person) 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 Ancillary Services"). The capability for these **Commercial Ancillary Services** is set out in the relevant **Ancillary Services Agreement** or **Bilateral Agreement** (as the case may be).
APPENDIX E1 - SITE RESPONSIBILITY SCHEDULES

FORMAT, PRINCIPLES AND BASIC PROCEDURE TO BE USED IN THE PREPARATION OF SITE RESPONSIBILITY SCHEDULES

ECC.A.1.1 Principles

Types of Schedules

ECC.A.1.1.1 At all Complexes (which in the context of this ECC shall include, Interface Sites until the OTSUA Transfer Time) the following Site Responsibility Schedules shall be drawn up using the relevant proforma attached or with such variations as may be agreed between The Company and Users, but in the absence of agreement the relevant proforma attached will be used. In addition, in the case of OTSDUW Plant and Apparatus, and in readiness for the OTSUA Transfer Time, the User shall provide The Company with the necessary information such that Site Responsibility Schedules in this form can be prepared by the Relevant Transmission Licensees for the Transmission Interface Site:

(a) Schedule of HV Apparatus
(b) Schedule of Plant, LV/MV Apparatus, services and supplies;
(c) Schedule of telecommunications and measurements Apparatus.

Other than at Power Generating Module (including DC Connected Power Park Modules) and Power Station locations, the schedules referred to in (b) and (c) may be combined.

New Connection Sites

ECC.A.1.1.2 In the case of a new Connection Site each Site Responsibility Schedule for a Connection Site shall be prepared by The Company in consultation with relevant Users at least 2 weeks prior to the Completion Date (or, where the OTSUA is to become Operational prior to the OTSUA Transfer Time, an alternative date) under the Bilateral Agreement and/or Construction Agreement for that Connection Site (which may form part of a Complex). In the case of a new Interface Site where the OTSUA is to become Operational prior to the OTSUA Transfer Time each Site Responsibility Schedule for an Interface Site shall be prepared by The Company in consultation with relevant Users at least 2 weeks prior to the Completion Date under the Bilateral Agreement and/or Construction Agreement for that Interface Site (which may form part of a Complex) (and references to and requirements placed on “Connection Site” in this ECC shall also be read as “Interface Site” where the context requires and until the OTSUA Transfer Time). Each User shall, in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement, provide information to The Company to enable it to prepare the Site Responsibility Schedule.

Sub-division

ECC.A.1.1.3 Each Site Responsibility Schedule will be subdivided to take account of any separate Connection Sites on that Complex.

Scope

ECC.A.1.1.4 Each Site Responsibility Schedule shall detail for each item of Plant and Apparatus:

(a) Plant/Apparatus ownership;
(b) Site Manager (Controller) (except in the case of Plant/Apparatus located in SPT's Transmission Area);
(c) Safety issues comprising applicable Safety Rules and Control Person or other responsible person (Safety Co-ordinator), or such other person who is responsible for safety;
(d) Operations issues comprising applicable Operational Procedures and control engineer;
(e) Responsibility to undertake statutory inspections, fault investigation and maintenance.
Each **Connection Point** shall be precisely shown.

**ECC.A.1.1.5** (a) In the case of **Site Responsibility Schedules** referred to in ECC.A.1.1.1(b) and (c), with the exception of **Protection Apparatus** and **Intertrip Apparatus** operation, it will be sufficient to indicate the responsible **User** or **Transmission Licensee**, as the case may be.

(b) In the case of the **Site Responsibility Schedule** referred to in ECC.A.1.1.1(a) and for **Protection Apparatus** and **Intertrip Apparatus**, the responsible management unit must be shown in addition to the **User** or **Transmission Licensee**, as the case may be.

**ECC.A.1.1.6** The **HV Apparatus Site Responsibility Schedule** for each **Connection Site** must include lines and cables emanating from or traversing the **Connection Site**.

**ECC.A.1.1.7** Every page of each **Site Responsibility Schedule** shall bear the date of issue and the issue number.

**ECC.A.1.1.8** When a **Site Responsibility Schedule** is prepared it shall be sent by **The Company** to the **Users** involved for confirmation of its accuracy.

**ECC.A.1.1.9** The **Site Responsibility Schedule** shall then be signed on behalf of **The Company** by its **Responsible Manager** (see ECC.A.1.1.16) and on behalf of each **User** involved by its **Responsible Manager** (see ECC.A.1.1.16), by way of written confirmation of its accuracy. The **Site Responsibility Schedule** will also be signed on behalf of the **Relevant Transmission Licensee** by its **Responsible Manager**.

**ECC.A.1.1.10** Once signed, two copies will be distributed by **The Company**, not less than two weeks prior to its implementation date, to each **User** which is a party on the **Site Responsibility Schedule**, accompanied by a note indicating the issue number and the date of implementation.

**ECC.A.1.1.11** **The Company** and **Users** must make the **Site Responsibility Schedules** readily available to operational staff at the **Complex** and at the other relevant control points.

**ECC.A 1.1.12** Without prejudice to the provisions of ECC.A.1.1.15 which deals with urgent changes, when a **User** identified on a **Site Responsibility Schedule** becomes aware that an alteration is necessary, it must inform **The Company** immediately and in any event 8 weeks prior to any change taking effect (or as soon as possible after becoming aware of it, if less than 8 weeks remain when the **User** becomes aware of the change). This will cover the commissioning of new **Plant** and/or **Apparatus** at the **Connection Site**, whether requiring a revised **Bilateral Agreement** or not, de-commissioning of **Plant** and/or **Apparatus**, and other changes which affect the accuracy of the **Site Responsibility Schedule**.

**ECC.A 1.1.13** Where **The Company** has been informed of a change by a **User**, or itself proposes a change, it will prepare a revised **Site Responsibility Schedule** by not less than six weeks prior to the change taking effect (subject to it having been informed or knowing of the change eight weeks prior to that time) and the procedure set out in ECC.A.1.1.8 shall be followed with regard to the revised **Site Responsibility Schedule**.

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1 Details of circuits traversing the **Connection Site** are only needed from the date which is the earlier of the date when the **Site Responsibility Schedule** is first updated and 15th October 2004. In Scotland or Offshore, from a date to be agreed between **The Company** and the **Relevant Transmission Licensee**.
The revised Site Responsibility Schedule shall then be signed in accordance with the procedure set out in ECC.A.1.1.9 and distributed in accordance with the procedure set out in ECC.A.1.1.10, accompanied by a note indicating where the alteration(s) has/have been made, the new issue number and the date of implementation.

**Urgent Changes**

When a User identified on a Site Responsibility Schedule, or The Company, as the case may be, becomes aware that an alteration to the Site Responsibility Schedule is necessary urgently to reflect, for example, an emergency situation which has arisen outside its control, the User shall notify The Company, or The Company shall notify the User, as the case may be, immediately and will discuss:

(a) what change is necessary to the Site Responsibility Schedule;
(b) whether the Site Responsibility Schedule is to be modified temporarily or permanently;
(c) the distribution of the revised Site Responsibility Schedule.

The Company will prepare a revised Site Responsibility Schedule as soon as possible, and in any event within seven days of it being informed of or knowing the necessary alteration. The Site Responsibility Schedule will be confirmed by Users and signed on behalf of The Company and Users and the Relevant Transmission Licensee (by the persons referred to in ECC.A.1.1.9) as soon as possible after it has been prepared and sent to Users for confirmation.

### Responsible Managers

Each User shall, prior to the Completion Date under each Bilateral Agreement and/or Construction Agreement, supply to The Company a list of Managers who have been duly authorised to sign Site Responsibility Schedules on behalf of the User and The Company shall, prior to the Completion Date under each Bilateral Agreement and/or Construction Agreement, supply to that User the name of its Responsible Manager and the name of the Relevant Transmission Licensee’s Responsible Manager and each shall supply to the other any changes to such list six weeks before the change takes effect where the change is anticipated, and as soon as possible after the change, where the change was not anticipated.

### De-commissioning of Connection Sites

Where a Connection Site is to be de-commissioned, whichever of The Company or the User who is initiating the de-commissioning must contact the other to arrange for the Site Responsibility Schedule to be amended at the relevant time.
# PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

<table>
<thead>
<tr>
<th>ITEM OF PLANT/APPARATUS</th>
<th>PLANT APPARATUS OWNER</th>
<th>SITE MANAGER</th>
<th>SAFETY RULES</th>
<th>CONTROL OR OTHER RESPONSIBLE PERSON (SAFETY COORDINATOR)</th>
<th>OPERATIONAL PROCEDURES</th>
<th>PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION &amp; MAINTENANCE</th>
<th>REMARKS</th>
</tr>
</thead>
</table>

COMPLEX: ___________________________  SCHEDULE: ______________

CONNECTION SITE: ________________

AREA

SAFETY

OPERATIONS
PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

__________________________ AREA

COMPLEX: ____________________ SCHEDULE: ____________

CONNECTION SITE: ______________

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<th>ITEM OF PLANT/APPARATUS</th>
<th>PLANT APPARATUS OWNER</th>
<th>SITE MANAGER</th>
<th>SAFETY RULES</th>
<th>SAFETY RESPONSIBLE PERSON (SAFETY COORDINATOR)</th>
<th>OPERATIONAL PROCEDURES</th>
<th>PARTY RESPONSIBLE FOR UNDERTAKING STATUTORY INSPECTIONS, FAULT INVESTIGATION &amp; MAINTENANCE</th>
<th>REMARKS</th>
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NOTES:

__________________________ D: ____________   ___________________________ E: ____________   ___________________________ Y: ____________   ___________________________ E: ____________
**SP TRANSMISSION Ltd**

**SITE RESPONSIBILITY SCHEDULE**

**OWNERSHIP, MAINTENANCE AND OPERATIONS OF EQUIPMENT**

**IN JOINT USER SITUATIONS**

<table>
<thead>
<tr>
<th>OWNER</th>
<th>ACCESS REQUIRED:</th>
<th>NAME:</th>
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<tr>
<td>LESSEE</td>
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<td>MAINTENANCE</td>
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<td>ADDRESS:</td>
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<td>SAFETY</td>
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<tr>
<td>SECURITY</td>
<td>LOCATION OF SUPPLY TERMINALS:</td>
<td>SUB STATION:</td>
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### SECTION 'C' PLANT

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<thead>
<tr>
<th>ITEM No.</th>
<th>EQUIPMENT</th>
<th>IDENTIFICATION</th>
<th>OWNER</th>
<th>SAFETY RULES</th>
<th>APPLICABLE</th>
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<tr>
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<th>Tapping</th>
<th>Closing</th>
<th>Isolating</th>
<th>Earthing</th>
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<td>Protection</td>
<td>Equip</td>
<td>Protection</td>
<td>Equip</td>
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<tr>
<td>FAULT INVESTIGATION</td>
<td>Protection</td>
<td>Equip</td>
<td>Repair</td>
<td>Equip</td>
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<tr>
<td>TESTING</td>
<td>Trip and Alarm</td>
<td>Protection</td>
<td>Equip</td>
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<th>RELAY SETTINGS</th>
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### SECTION 'D' CONFIGURATION AND CONTROL

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<th>TELEPHONE NUMBER</th>
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<th>TELEPHONE NUMBER</th>
<th>REMARKS</th>
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### SECTION 'E' ADDITIONAL INFORMATION

**SIGNatures:**

- D - SP AUTHORISED PERSON - DISTRIBUTION SYSTEM
- INCO - NATIONAL GRID COMPANY
- SPDL - SP DISTRIBUTION LTD
- SPS - POWER SYSTEMS LTD
- T - SCOTTISH POWER TELECOMMUNICATIONS
- U - SP AUTHORISED PERSON - TRANSMISSION SYSTEM
- USER

**SIGNED**

FOR: SP Transmission
DATE: __________

FOR: SP Distribution
DATE: __________

FOR: PowerSystemsUser
DATE: __________
Scottish Hydro-Electric Transmission Limited

Site Responsibility Schedule

<table>
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<tr>
<th>Substation Type</th>
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TRANSFORMERS
(VECTORS TO INDICATE WINDING CONFIGURATION)

TWO WINDING

THREE WINDING

AUTO

AUTO WITH DELTA TERTIARY

EARTHING OR AUX. TRANSFORMER
(−) INDICATE REMOTE SITE IF APPLICABLE

VOLTAGE TRANSFORMERS

SINGLE PHASE WOUND

THREE PHASE WOUND

SINGLE PHASE CAPACITOR

TWO SINGLE PHASE CAPACITOR

THREE PHASE CAPACITOR

* CURRENT TRANSFORMER (WHERE SEPARATE PRIMARY APPARATUS)

* COMBINED VT/CT UNIT FOR METERING

* BUSBARS

* OTHER PRIMARY CONNECTIONS

* CABLE & CABLE SEALING END

* THROUGH WALL BUSHING

* BYPASS FACILITY

* CROSSING OF CONDUCTORS (LOWER CONDUCTOR TO BE BROKEN)

415V (−)

PREPARATORY ABBREVIATIONS

AUXILIARY TRANSFORMER Aux T
EARTHING TRANSFORMER ET
GAS TURBINE Gas T
GENERATOR TRANSFORMER Gen T
GRID TRANSFORMER Gr T
SERIES REACTOR Ser Req
SHUNT REACTOR Sh Req
STATION TRANSFORMER Stn T
SUPERGRID TRANSFORMER SGT
UNIT TRANSFORMER UT

* NON-STANDARD SYMBOL
PART E1B - PROCEDURES RELATING TO GAS ZONE DIAGRAMS

- **GAS INSULATED BUSBAR**
- **DOUBLE-BREAK DISCONNECTOR**

- **GAS BOUNDARY**
- **EXTERNAL MOUNTED CURRENT TRANSFORMER (WHERE SEPARATE PRIMARY APPARATUS)**

- **GAS/GAS BOUNDARY**
- **STOP VALVE NORMALLY CLOSED**

- **GAS/CABLE BOUNDARY**
- **STOP VALVE NORMALLY OPEN**

- **GAS/AIR BOUNDARY**
- **GAS MONITOR**

- **GAS/TRANSFORMER BOUNDARY**
- **FILTER**

- **MAINTENANCE VALVE**
- **QUICK ACTING COUPLING**
PART E2 - NON-EXHAUSTIVE LIST OF APPARATUS
TO BE INCLUDED ON OPERATION DIAGRAMS

**Basic Principles**

(1) Where practicable, all the **HV Apparatus** on any **Connection Site** shall be shown on one **Operation Diagram**. Provided the clarity of the diagram is not impaired, the layout shall represent as closely as possible the geographical arrangement on the **Connection Site**.

(2) Where more than one **Operation Diagram** is unavoidable, duplication of identical information on more than one **Operation Diagram** must be avoided.

(3) The **Operation Diagram** must show accurately the current status of the **Apparatus** e.g. whether commissioned or decommissioned. Where decommissioned, the associated switchbay will be labelled "spare bay".

(4) Provision will be made on the **Operation Diagram** for signifying approvals, together with provision for details of revisions and dates.

(5) **Operation Diagrams** will be prepared in A4 format or such other format as may be agreed with **The Company**.

(6) The **Operation Diagram** should normally be drawn single line. However, where appropriate, detail which applies to individual phases shall be shown. For example, some **HV Apparatus** is numbered individually per phase.

**Apparatus To Be Shown On Operation Diagram**

(1) Busbars
(2) Circuit Breakers
(3) Disconnector (Isolator) and Switch Disconnecters (Switching Isolators)
(4) Disconnectors (Isolators) - Automatic Facilities
(5) Bypass Facilities
(6) Earthing Switches
(7) Maintenance Earths
(8) Overhead Line Entries
(9) Overhead Line Traps
(10) Cable and Cable Sealing Ends
(11) Generating Unit
(12) Generator Transformers
(13) Generating Unit Transformers, Station Transformers, including the lower voltage circuit-breakers.
(14) Synchronous Compensators
(15) Static Variable Compensators
(16) Capacitors (including Harmonic Filters)
(17) Series or Shunt Reactors (Referred to as "Inductors" at nuclear power station sites)
(18) Supergrid and Grid Transformers
(19) Tertiary Windings
(20) Earthing and Auxiliary Transformers
(21) Three Phase VT’s
(22) Single Phase VT & Phase Identity
(23) High Accuracy VT and Phase Identity
(24) Surge Arrestors/Diverters
(25) Neutral Earthing Arrangements on HV Plant
(26) Fault Throwing Devices
(27) Quadrature Boosters
(28) Arc Suppression Coils
(29) Single Phase Transformers (BR) Neutral and Phase Connections
(30) Current Transformers (where separate plant items)
(31) Wall Bushings
(32) Combined VT/CT Units
(33) Shorting and Discharge Switches
(34) Thyristor
(35) Resistor with Inherent Non-Linear Variability, Voltage Dependent
(36) Gas Zone
APPENDIX E3 - MINIMUM FREQUENCY RESPONSE CAPABILITY REQUIREMENT PROFILE AND OPERATING RANGE FOR POWER GENERATING MODULES AND HVDC EQUIPMENT

ECC.A.3.1 Scope
The frequency response capability is defined in terms of Primary Response, Secondary Response and High Frequency Response. In addition to the requirements defined in ECC.6.3.7 this appendix defines the minimum frequency response requirements for:

(a) each Type C and Type D Power Generating Module
(b) each DC Connected Power Park Module
(c) each HVDC System

For the avoidance of doubt, this appendix does not apply to Type A and Type B Power Generating Modules.

OTSDUW Plant and Apparatus should facilitate the delivery of frequency response services provided by Offshore Generating Units and Offshore Power Park Units.

The functional definition provides appropriate performance criteria relating to the provision of Frequency control by means of Frequency sensitive generation in addition to the other requirements identified in ECC.6.3.7.

In this Appendix 3 to the ECC, for a Power Generating Module including a CCGT Module or a Power Park Module or DC Connected Power Park Module, the phrase Minimum Regulating Level applies to the entire CCGT Module or Power Park Module or DC Connected Power Park Module operating with all Generating Units Synchronised to the System.

The minimum Frequency response requirement profile is shown diagrammatically in Figure ECC.A.3.1. The capability profile specifies the minimum required level of Frequency Response Capability throughout the normal plant operating range.

ECC.A.3.2 Plant Operating Range
The upper limit of the operating range is the Maximum Capacity of the Power Generating Module or Generating Unit or CCGT Module or HVDC Equipment.

The Minimum Stable Operating Level may be less than, but must not be more than, 65% of the Maximum Capacity. Each Power Generating Module and/or Generating Unit and/or CCGT Module and/or Power Park Module or HVDC Equipment must be capable of operating satisfactorily down to the Minimum Regulating Level as dictated by System operating conditions, although it will not be instructed to below its Minimum Stable Operating Level. If a Power Generating Module or Generating Unit or CCGT Module or Power Park Module, or HVDC Equipment is operating below Minimum Stable Operating Level because of high System Frequency, it should recover adequately to its Minimum Stable Operating Level as the System Frequency returns to Target Frequency so that it can provide Primary and Secondary Response from its Minimum Stable Operating Level if the System Frequency continues to fall. For the avoidance of doubt, under normal operating conditions steady state operation below the Minimum Stable Operating Level is not expected. The Minimum Regulating Level must not be more than 55% of Maximum Capacity.

In the event of a Power Generating Module or Generating Unit or CCGT Module or Power Park Module or HVDC Equipment load rejecting down to no less than its Minimum Regulating Level it should not trip as a result of automatic action as detailed in BC3.7. If the load rejection is to a level less than the Minimum Regulating Level then it is accepted that the condition might be so severe as to cause it to be disconnected from the System.

ECC.A.3.3 Minimum Frequency Response Requirement Profile
Figure ECC.A.3.1 shows the minimum Frequency response capability requirement profile diagrammatically for a 0.5 Hz change in Frequency. The percentage response capabilities and loading levels are defined on the basis of the Maximum Capacity of the Power Generating Module or CCGT Module or Power Park Module or HVDC Equipment. Each Power Generating Module or and/or CCGT Module or Power Park Module (including a DC Connected Power Park Module) and/or HVDC Equipment must be capable of operating in a manner to provide Frequency response at least to the solid boundaries shown in the figure. If the Frequency response capability falls within the solid boundaries, the Power Generating Module or CCGT Module or Power Park Module or HVDC Equipment is providing response below the minimum requirement which is not acceptable. Nothing in this appendix is intended to prevent a Power Generating Module or CCGT Module or Power Park Module or HVDC Equipment from being designed to deliver a Frequency response in excess of the identified minimum requirement.

The Frequency response delivered for Frequency deviations of less than 0.5 Hz should be no less than a figure which is directly proportional to the minimum Frequency response requirement for a Frequency deviation of 0.5 Hz. For example, if the Frequency deviation is 0.2 Hz, the corresponding minimum Frequency response requirement is 40% of the level shown in Figure ECC.A.3.1. The Frequency response delivered for Frequency deviations of more than 0.5 Hz should be no less than the response delivered for a Frequency deviation of 0.5 Hz.

Each Power Generating Module and/or CCGT Module and/or Power Park Module or HVDC Equipment must be capable of providing some response, in keeping with its specific operational characteristics, when operating between 95% to 100% of Maximum Capacity as illustrated by the dotted lines in Figure ECC.A.3.1.

At the Minimum Stable Operating level, each Power Generating Module and/or CCGT Module and/or Power Park Module and/or HVDC Equipment is required to provide high and low frequency response depending on the System Frequency conditions. Where the Frequency is high, the Active Power output is therefore expected to fall below the Minimum Stable Operating level.

The Minimum Regulating Level is the output at which a Power Generating Module and/or CCGT Module and/or Power Park Module and/or HVDC Equipment has no High Frequency Response capability. It may be less than, but must not be more than, 55% of the Maximum Capacity. This implies that a Power Generating Module or CCGT Module or Power Park Module or HVDC Equipment is not obliged to reduce its output to below this level unless the Frequency is at or above 50.5 Hz (cf BC3.7).

ECC.A.3.4 Testing of Frequency Response Capability

The frequency response capabilities shown diagrammatically in Figure ECC.A.3.1 are measured by taking the responses as obtained from some of the dynamic step response tests specified by The Company and carried out by Generators and HVDC System owners for compliance purposes. The injected signal is a step of 0.5 Hz from zero to 0.5 Hz Frequency change, and is sustained at 0.5 Hz Frequency change thereafter, the latter as illustrated diagrammatically in figures ECC.A.3.4 and ECC.A.3.5.

In addition to provide and/or to validate the content of Ancillary Services Agreements a progressive injection of a Frequency change to the plant control system (i.e. governor and load controller) is used. The injected signal is a ramp of 0.5 Hz from zero to 0.5 Hz Frequency change over a ten second period, and is sustained at 0.5 Hz Frequency change thereafter, the latter as illustrated diagrammatically in figures ECC.A.3.2 and ECC.A.3.3. In the case of an Embedded Medium Power Station not subject to a Bilateral Agreement or Embedded HVDC System not subject to a Bilateral Agreement, The Company may require the Network Operator within whose System the Embedded Medium Power Station or Embedded HVDC System is situated, to ensure that the Embedded Person performs the dynamic response tests reasonably required by The Company in order to demonstrate compliance within the relevant requirements in the ECC.
The **Primary Response** capability (P) of a Power Generating Module or a CCGT Module or Power Park Module or HVDC Equipment is the minimum increase in **Active Power** output between 10 and 30 seconds after the start of the ramp injection as illustrated diagrammatically in Figure ECC.A.3.2. This increase in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** fall as illustrated by the response from Figure ECC.A.3.2.

The **Secondary Response** capability (S) of a Power Generating Module or a CCGT Module or Power Park Module or HVDC Equipment is the minimum increase in **Active Power** output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated diagrammatically in Figure ECC.A.3.2.

The **High Frequency Response** capability (H) of a Power Generating Module or a CCGT Module or Power Park Module or HVDC Equipment is the decrease in **Active Power** output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated diagrammatically in Figure ECC.A.3.3. This reduction in **Active Power** output should be released increasingly with time over the period 0 to 10 seconds from the time of the start of the **Frequency** rise as illustrated by the response in Figure ECC.A.3.2.

**ECC.A.3.5 Repeatability Of Response**

When a Power Generating Module or CCGT Module or Power Park Module or HVDC Equipment has responded to a significant **Frequency** disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than 20 minutes after the initial change of **System Frequency** arising from the **Frequency** disturbance.
Figure ECC.A.3.1 - Minimum Frequency Response requirement profile for a 0.5 Hz frequency change from Target Frequency.
Figure ECC.A.3.2 – Interpretation of Primary and Secondary Response Service Values

Figure ECC.A.3.3 – Interpretation of High Frequency Response Service Values
Figure ECC.A.3.4 – Interpretation of Low Frequency Response Capability Values

Figure ECC.A.3.5 – Interpretation of High Frequency Response Capability Values
ECC.4 - APPENDIX 4 - FAULT RIDE THROUGH REQUIREMENTS

FAULT RIDE THROUGH REQUIREMENTS FOR TYPE B, TYPE C AND TYPE D POWER GENERATING MODULES (INCLUDING OFFSHORE POWER PARK MODULES WHICH ARE EITHER AC CONNECTED POWER PARK MODULES OR DC CONNECTED POWER PARK MODULES), HVDC SYSTEMS AND OTSDUW PLANT AND APPARATUS

ECC.A.4A.1 Scope

The Fault Ride Through requirements are defined in ECC.6.3.15. This Appendix provides illustrations by way of examples only of ECC.6.3.15.1 to ECC.6.3.15.10 and further background and illustrations and is not intended to show all possible permutations.

ECC.A.4A.2 Short Circuit Faults At Supergrid Voltage On The Onshore Transmission System Up To 140ms In Duration

For short circuit faults at Supergrid Voltage on the Onshore Transmission System (which could be at an Interface Point) up to 140ms in duration, the Fault Ride Through requirement is defined in ECC.6.3.15. In summary any Power Generating Module (including a DC Connected Power Park Module) or HVDC System is required to remain connected and stable whilst connected to a healthy circuit. Figure ECC.A.4.A.2 illustrates this principle.

In Figure ECC.A.4.A.2 a solid three phase short circuit fault is applied adjacent to substation A resulting in zero voltage at the point of fault. All circuit breakers on the faulty circuit (Lines ABC) will open within 140ms resulting in Gen X tripping. The effect of this fault, due to the low impedance of the network, will be the observation of a low voltage at each substation node across the Total System until the fault has been cleared. In this example, Gen Y and Gen Z (an Embedded Generator) would need to remain connected and stable as both are still connected to the Total System and remain connected to healthy circuits.

The criteria for assessment is based on a voltage against time curve at each Grid Entry Point or User System Entry Point. The voltage against time curve at the Grid Entry Point or User System Entry Point varies for each different type and size of Power Generating Module as detailed in ECC.6.3.15.2. – ECC.6.3.15.7.
The voltage against time curve represents the voltage profile at a **Grid Entry Point or User System Entry Point** that would be obtained by plotting the voltage at that Grid Entry Point or User System Entry Point before during and after the fault. This is not to be confused with a voltage duration curve (as defined under ECC.6.3.15.9) which represents a voltage level and associated time duration.

The post fault voltage at a Grid Entry Point or User System Entry Point is largely influenced by the topology of the network rather than the behaviour of the Power Generating Module itself. The EU Generator therefore needs to ensure each Power Generating Module remains connected and stable for a close up solid three phase short circuit fault for 140ms at the Grid Entry Point or User System Entry Point.

Two examples are shown in Figure EA.4.2(a) and Figure EA.4.2(b). In Figure EA.4.2(a) the post fault profile is above the heavy black line. In this case the Power Generating Module must remain connected and stable. In Figure EA.4.2(b) the post fault voltage dips below the heavy black line in which case the Power Generating Module is permitted to trip.

The process for demonstrating **Fault Ride Through** compliance against the requirements of ECC.6.3.15 is detailed in ECP.A.3.5 and ECP.A.6.7 (as applicable).

**ECC.A.4A.3**  
Supergrid Voltage Dips On The Onshore Transmission System Greater Than 140ms In Duration

**ECC.A.4A3.1**  
Requirements applicable to Synchronous Power Generating Modules subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.
For balanced **Supergrid Voltage** dips on the **Onshore Transmission System** having durations greater than 140ms and up to 3 minutes, the **Fault Ride Through** requirement is defined in ECC.6.3.15.9.2.1(a) and Figure ECC.6.3.15.9(a) which is reproduced in this Appendix as Figure EA.4.3.1 and termed the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at a point on the **Onshore Transmission System** (or **User System** if located **Onshore**) to a disturbance. Rather, each point on the profile (ie the heavy black line) represents a voltage level and an associated time duration which connected **Synchronous Power Generating Modules** must withstand or ride through.

Figures EA.4.3.2 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

![Figure EA.4.3.1](image)

**Figure EA.4.3.1**

![Figure EA.4.3.2 (a)](image)

**Figure EA.4.3.2 (a)**
Requirements applicable to Power Park Modules or OTSDUW Plant and Apparatus subject to Supergrid Voltage dips on the Onshore Transmission System greater than 140ms in duration.

For balanced Supergrid Voltage dips on the Onshore Transmission System (which could be at an Interface Point) having durations greater than 140ms and up to 3 minutes the Fault Ride Through requirement is defined in ECC.6.3.15.9.2.1(b) and Figure ECC.6.3.15.9(b) which is reproduced in this Appendix as Figure EA.4.3.3 and termed the voltage–duration profile.

This profile is not a voltage-time response curve that would be obtained by plotting the transient voltage response at a point on the Onshore Transmission System (or User System if located Onshore) to a disturbance. Rather, each point on the profile (ie the heavy black line) represents a voltage level and an associated time duration which connected Power Park Modules or OTSDUW Plant and Apparatus must withstand or ride through.
Figures EA.4.3.4 (a), (b) and (c) illustrate the meaning of the voltage-duration profile for voltage dips having durations greater than 140ms.

![Figure EA.4.3.3](image)

Figure EA.4.3.3

![Figure EA.4.3.4(a)](image)

Figure EA.4.3.4(a)
Figure EA.4.3.4 (b)  

50% retained voltage, 710 ms duration

Figure EA.4.3.4 (c)  

85% retained voltage, 3 minutes duration
APPENDIX E5 - TECHNICAL REQUIREMENTS
LOW FREQUENCY RELAYS FOR THE AUTOMATIC DISCONNECTION OF SUPPLIES AT LOW FREQUENCY

ECC.A.5.1 Low Frequency Relays
ECC.A.5.1.1 The Low Frequency Relays to be used shall have a setting range of 47.0 to 50Hz and be suitable for operation from a nominal AC input of 63.5, 110 or 240V. The following-parameters specify the requirements of approved Low Frequency Relays:

(a) Frequency settings: 47-50Hz in steps of 0.05Hz or better, preferably 0.01Hz;
(b) Operating time: Relay operating time shall not be more than 150 ms;
(c) Voltage lock-out: Selectable within a range of 55 to 90% of nominal voltage;
(d) Direction: Tripping interlock for forward or reverse power flow capable of being set in either position or off;
(e) Facility stages: One or two stages of Frequency operation;
(f) Output contacts: Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations;
(g) Accuracy: 0.01 Hz maximum error under reference environmental and system voltage conditions.
0.05 Hz maximum error at 8% of total harmonic distortion

Electromagnetic Compatibility Level.

In the case of Network Operators who are GB Code Users, the above requirements only apply to a relay (if any) installed at the EU Grid Supply Point. Network Operators who are also GB Code Users should continue to satisfy the requirements for low frequency relays as specified in the CCs as applicable to their System.

ECC.A.5.2 Low Frequency Relay Voltage Supplies
ECC.A.5.2.1 It is essential that the voltage supply to the Low Frequency Relays shall be derived from the primary System at the supply point concerned so that the Frequency of the Low Frequency Relays input voltage is the same as that of the primary System. This requires either:

(a) the use of a secure supply obtained from voltage transformers directly associated with the grid transformer(s) concerned, the supply being obtained where necessary via a suitable automatic voltage selection scheme; or
(b) the use of the substation 240V phase-to-neutral selected auxiliary supply, provided that this supply is always derived at the supply point concerned and is never derived from a standby supply Power Generating Module or from another part of the User System.

ECC.A.5.3 Scheme Requirements
ECC.A.5.3.1 The tripping facility should be engineered in accordance with the following reliability considerations:

(a) Dependability
Failure to trip at any one particular Demand shedding point would not harm the overall operation of the scheme. However, many failures would have the effect of reducing the amount of Demand under low Frequency control. An overall reasonable minimum requirement for the dependability of the Demand shedding scheme is 96%, i.e. the average probability of failure of each Demand shedding point should be less than 4%. Thus the Demand under low Frequency control will not be reduced by more than 4% due to relay failure.

(b) Outages

Low Frequency Demand shedding schemes will be engineered such that the amount of Demand under control is as specified in Table ECC.A.5.5.1a and is not reduced unacceptably during equipment outage or maintenance conditions.

ECC.A.5.3.2 The total operating time of the scheme, including circuit breakers operating time, shall where reasonably practicable, be less than 200 ms. For the avoidance of doubt, the replacement of plant installed prior to October 2009 will not be required in order to achieve lower total scheme operating times.

ECC.A.5.4 Low Frequency Relay Testing

ECC.A.5.4.1 Low Frequency Relays installed and commissioned after 1st January 2007 shall be type tested in accordance with and comply with the functional test requirements for Frequency Protection contained in Energy Networks Association Technical Specification 48-6-5 Issue 1 dated 2005 “ENA Protection Assessment Functional Test Requirements – Voltage and Frequency Protection”.

For the avoidance of doubt, Low Frequency Relays installed and commissioned before 1st January 2007 shall comply with the version of ECC.A.5.1.1 applicable at the time such Low Frequency Relays were commissioned.

ECC.A.5.4.2 Each Non-Embedded Customer shall aim to execute testing on its low frequency demand disconnection relays installed within its network and in service at least once every three years, although this may be extended to no more than every five years if considered to be required for operational purposes.

ECC.A.5.4.3 Each Network Operator and Relevant Transmission Licensee shall aim to execute testing on its low frequency demand disconnection relays installed within its network and in service at least once every three years, although this may be extended to no more than every five years if considered to be required for operational purposes.

ECC.A.5.5 Scheme Settings

ECC.A.5.5.1 Table CC.A.5.5.1a shows, for each Transmission Area, the percentage of Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand that each Network Operator whose System is connected to the Onshore Transmission System within such Transmission Area shall disconnect by Low Frequency Relays at a range of frequencies. Where a Network Operator’s System is connected to the National Electricity Transmission System in more than one Transmission Area, the settings for the Transmission Area in which the majority of the Demand is connected shall apply.

<table>
<thead>
<tr>
<th>Frequency Hz</th>
<th>% Demand disconnection for each Network Operator in Transmission Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>48.8</td>
<td>NGET 5 SPT 5 SHETL 5</td>
</tr>
<tr>
<td>48.75</td>
<td>NGET 5 SPT 5 SHETL 5</td>
</tr>
<tr>
<td>48.7</td>
<td>10</td>
</tr>
<tr>
<td>-------</td>
<td>-----</td>
</tr>
<tr>
<td>48.6</td>
<td>7.5</td>
</tr>
<tr>
<td>48.5</td>
<td>7.5</td>
</tr>
<tr>
<td>48.4</td>
<td>7.5</td>
</tr>
<tr>
<td>48.2</td>
<td>7.5</td>
</tr>
<tr>
<td>48.0</td>
<td>5</td>
</tr>
<tr>
<td>47.8</td>
<td>5</td>
</tr>
<tr>
<td><strong>Total % Demand</strong></td>
<td><strong>60</strong></td>
</tr>
</tbody>
</table>

Table ECC.A.5.5.1a

Note – the percentages in table ECC.A.5.5.1a are cumulative such that, for example, should the frequency fall to 48.6 Hz in NGET’s Transmission Area, 27.5% of the total Demand connected to the National Electricity Transmission System in NGET’s Transmission Area shall be disconnected by the action of Low Frequency Relays.

The percentage Demand at each stage shall be allocated as far as reasonably practicable. The cumulative total percentage Demand is a minimum.

ECC.A.5.5.2 In the case of a Non-Embedded Customer (who is also an EU Code User) the percentage of Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand that each Non-Embedded Customer whose System is connected to the Onshore Transmission System which shall be disconnected by Low Frequency Relays shall be in accordance with OC6.6 and the Bilateral Agreement.

ECC.A.5.6 Connection and Reconnection

ECC.A.5.6.1 As defined under OC.6.6 once automatic low Frequency Demand Disconnection has taken place, the Network Operator on whose User System it has occurred, will not reconnect until The Company instructs that Network Operator to do so in accordance with OC6. The same requirement equally applies to Non-Embedded Customers.

ECC.A.5.6.2 Once The Company instructs the Network Operator or Non Embedded Customer to reconnect to the National Electricity Transmission System following operation of the Low Frequency Demand Disconnection scheme it shall do so in accordance with the requirements of ECC.6.2.3.10 and OC6.6.

ECC.A.5.6.3 Network Operators or Non Embedded Customers shall be capable of being remotely disconnected from the National Electricity Transmission System when instructed by The Company. Any requirement for the automated disconnection equipment for reconfiguration of the National Electricity Transmission System in preparation for block loading and the time required for remote disconnection shall be specified by The Company in accordance with the terms of the Bilateral Agreement.
APPENDIX E6 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC EXCITATION CONTROL SYSTEMS FOR ONSHORE SYNCHRONOUS POWER GENERATING MODULES,

ECC.A.6.1 Scope

ECC.A.6.1.1 This Appendix sets out the performance requirements of continuously acting automatic excitation control systems for Type C and Type D Onshore Synchronous Power Generating Modules that must be complied with by the User. This Appendix does not limit any site specific requirements where in The Company's reasonable opinion these facilities are necessary for system reasons.

ECC.A.6.1.2 Where the requirements may vary the likely range of variation is given in this Appendix. It may be necessary to specify values outside this range where The Company identifies a system need, and notwithstanding anything to the contrary The Company may specify values outside of the ranges provided in this Appendix 6. The most common variations are in the on-load excitation ceiling voltage requirements and the response time required of the Exciter. Actual values will be included in the Bilateral Agreement.

ECC.A.6.1.3 Should an EU Generator anticipate making a change to the excitation control system it shall notify The Company under the Planning Code (PC.A.1.2(b) and (c)) as soon as the EU Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

ECC.A.6.2 Requirements

ECC.A.6.2.1 The Excitation System of a Type C or Type D Onshore Synchronous Power Generating Module shall include an excitation source (Exciter), and a continuously acting Automatic Voltage Regulator (AVR) and shall meet the following functional specification. Type D Synchronous Power Generating Modules are also required to be fitted with a Power System Stabiliser in accordance with the requirements of ECC.A.6.2.5.

ECC.A.6.2.2 Steady State Voltage Control

ECC.A.6.2.3.1 An accurate steady state control of the Onshore Synchronous Power Generating Module pre-set Synchronous Generating Unit terminal voltage is required. As a measure of the accuracy of the steady-state voltage control, the Automatic Voltage Regulator shall have static zero frequency gain, sufficient to limit the change in terminal voltage to a drop not exceeding 0.5% of rated terminal voltage, when the output of a Synchronous Generating Unit within an Onshore Synchronous Power Generating Module is gradually changed from zero to rated MVA output at rated voltage, Active Power and Frequency.

ECC.A.6.2.4 Transient Voltage Control

ECC.A.6.2.4.1 For a step change from 90% to 100% of the nominal Onshore Synchronous Generating Unit terminal voltage, with the Onshore Synchronous Generating Unit on open circuit, the Excitation System response shall have a damped oscillatory characteristic. For this characteristic, the time for the Onshore Synchronous Generating Unit terminal voltage to first reach 100% shall be less than 0.6 seconds. Also, the time to settle within 5% of the voltage change shall be less than 3 seconds.

ECC.A.6.2.4.2 To ensure that adequate synchronising power is maintained, when the Onshore Power Generating Module is subjected to a large voltage disturbance, the Exciter whose output is varied by the Automatic Voltage Regulator shall be capable of providing its achievable upper and lower limit ceiling voltages to the Onshore Synchronous Generating Unit field in a time not exceeding that specified in the Bilateral Agreement. This will normally be not less than 50 ms and not greater than 300 ms. The achievable upper and lower limit ceiling voltages may be dependent on the voltage disturbance.

ECC.A.6.2.4.3 The Exciter shall be capable of attaining an Excitation System On Load Positive Ceiling Voltage of not less than a value specified in the Bilateral Agreement that will be:
not less than 2 per unit (pu)
normally not greater than 3 pu
exceptionally up to 4 pu

of Rated Field Voltage when responding to a sudden drop in voltage of 10 percent or more at the Onshore Synchronous Generating Unit terminals. The Company may specify a value outside the above limits where The Company identifies a system need.

ECC.A.6.2.4.4 If a static type Exciter is employed:

(i) the field voltage should be capable of attaining a negative ceiling level specified in the Bilateral Agreement after the removal of the step disturbance of ECC.A.6.2.4.3. The specified value will be 80% of the value specified in ECC.A.6.2.4.3. The Company may specify a value outside the above limits where The Company identifies a system need.

(ii) the Exciter must be capable of maintaining free firing when the Onshore Synchronous Generating Unit terminal voltage is depressed to a level which may be between 20% to 30% of rated terminal voltage

(iii) the Exciter shall be capable of attaining a positive ceiling voltage not less than 80% of the Excitation System On Load Positive Ceiling Voltage upon recovery of the Onshore Synchronous Generating Unit terminal voltage to 80% of rated terminal voltage following fault clearance. The Company may specify a value outside the above limits where The Company identifies a system need.

(iv) the requirement to provide a separate power source for the Exciter will be specified if The Company identifies a Transmission System need.

ECC.A.6.2.5 Power Oscillations Damping Control

ECC.A.6.2.5.1 To allow Type D Onshore Power Generating Modules to maintain second and subsequent swing stability and also to ensure an adequate level of low frequency electrical damping power, the Automatic Voltage Regulator of each Onshore Synchronous Generating Unit within each Type D Onshore Synchronous Power Generating Module shall include a Power System Stabiliser as a means of supplementary control.

ECC.A.6.2.5.2 Whatever supplementary control signal is employed, it shall be of the type which operates into the Automatic Voltage Regulator to cause the field voltage to act in a manner which results in the damping power being improved while maintaining adequate synchronising power.

ECC.A.6.2.5.3 The arrangements for the supplementary control signal shall ensure that the Power System Stabiliser output signal relates only to changes in the supplementary control signal and not the steady state level of the signal. For example, if generator electrical power output is chosen as a supplementary control signal then the Power System Stabiliser output should relate only to changes in the Synchronous Generating Unit electrical power output and not the steady state level of power output. Additionally the Power System Stabiliser should not react to mechanical power changes in isolation for example during rapid changes in steady state load or when providing frequency response.

ECC.A.6.2.5.4 The output signal from the Power System Stabiliser shall be limited to not more than ±10% of the Onshore Synchronous Generating Unit terminal voltage signal at the Automatic Voltage Regulator input. The gain of the Power System Stabiliser shall be such that an increase in the gain by a factor of 3 shall not cause instability.

ECC.A.6.2.5.5 The Power System Stabiliser shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application.
ECC.A.6.2.5.6 The EU Generator in respect of its Type D Synchronous Power Generating Modules will agree Power System Stabiliser settings with The Company prior to the on-load commissioning detailed in BC2.11.2(d). To allow assessment of the performance before on-load commissioning the EU Generator will provide to The Company a report covering the areas specified in ECP.A.3.2.1.

ECC.A.6.2.5.7 The Power System Stabiliser must be active within the Excitation System at all times when Synchronised including when the Under Excitation Limiter or Over Excitation Limiter are active. When operating at low load when Synchronising or De-Synchronising an Onshore Synchronous Generating Unit, within a Type D Synchronous Power Generating Module, the Power System Stabiliser may be out of service.

ECC.A.6.2.5.8 Where a Power System Stabiliser is fitted to a Pumped Storage Unit within a Type D Synchronous Power Generating Module it must function when the Pumped Storage Unit is in both generating and pumping modes. In addition, where a Power System Stabiliser is fitted to an Electricity Storage Unit within a Type D Synchronous Electricity Storage Module, it must function when the Synchronous Electricity Storage Unit is in both importing and exporting modes of operation.

ECC.A.6.2.6 Overall Excitation System Control Characteristics

ECC.A.6.2.6.1 The overall Excitation System shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5 Hz will be judged to be acceptable for this application.

ECC.A.6.2.6.2 The response of the Automatic Voltage Regulator combined with the Power System Stabiliser shall be demonstrated by injecting similar step signal disturbances into the Automatic Voltage Regulator reference as detailed in ECPA.5.2 and ECPA.5.4. The Automatic Voltage Regulator shall include a facility to allow step injections into the Automatic Voltage Regulator voltage reference, with the Onshore Type D Power Generating Module operating at points specified by The Company (up to rated MVA output). The damping shall be judged to be adequate if the corresponding Active Power response to the disturbances decays within two cycles of oscillation.

ECC.A.6.2.6.3 A facility to inject a band limited random noise signal into the Automatic Voltage Regulator voltage reference shall be provided for demonstrating the frequency domain response of the Power System Stabiliser. The tuning of the Power System Stabiliser shall be judged to be adequate if the corresponding Active Power response shows improved damping with the Power System Stabiliser in combination with the Automatic Voltage Regulator compared with the Automatic Voltage Regulator alone over the frequency range 0.3Hz – 2Hz.

ECC.A.6.2.7 Under-Excitation Limiters

ECC.A.6.2.7.1 The security of the power system shall also be safeguarded by means of MVAR Under Excitation Limiters fitted to the Synchronous Power Generating Module Excitation System. The Under Excitation Limiter shall prevent the Automatic Voltage Regulator reducing the Synchronous Generating Unit excitation to a level which would endanger synchronous stability. The Under Excitation Limiter shall operate when the excitation system is providing automatic control. The Under Excitation Limiter shall respond to changes in the Active Power (MW) the Reactive Power (MVAR) and to the square of the Synchronous Generating Unit voltage in such a direction that an increase in voltage will permit an increase in leading MVAR. The characteristic of the Under Excitation Limiter shall be substantially linear from no-load to the maximum Active Power output of the Onshore Power Generating Module at any setting and shall be readily adjustable.
ECC.A.6.2.7.2 The performance of the Under Excitation Limiter shall be independent of the rate of change of the Onshore Synchronous Power Generating Module load and shall be demonstrated by testing as detailed in ECP.A.5.5. The resulting maximum overshoot in response to a step injection which operates the Under Excitation Limiter shall not exceed 4% of the Onshore Synchronous Generating Unit rated MVA. The operating point of the Onshore Synchronous Generating Unit shall be returned to a steady state value at the limit line and the final settling time shall not be greater than 5 seconds. When the step change in Automatic Voltage Regulator reference voltage is reversed, the field voltage should begin to respond without any delay and should not be held down by the Under Excitation Limiter. Operation into or out of the preset limit levels shall ensure that any resultant oscillations are damped so that the disturbance is within 0.5% of the Onshore Synchronous Generating Unit MVA rating within a period of 5 seconds.

ECC.A.6.2.7.3 The EU Generator shall also make provision to prevent the reduction of the Onshore Synchronous Generating Unit excitation to a level which would endanger synchronous stability when the Excitation System is under manual control.

ECC.A.6.2.8 Over-Excitation and Stator Current Limiters

ECC.A.6.2.8.1 The settings of the Over-Excitation Limiter and stator current limiter, shall ensure that the Onshore Synchronous Generating Unit excitation is not limited to less than the maximum value that can be achieved whilst ensuring the Onshore Synchronous Generating Unit is operating within its design limits. If the Onshore Synchronous Generating Unit excitation is reduced following a period of operation at a high level, the rate of reduction shall not exceed that required to remain within any time dependent operating characteristics of the Onshore Synchronous Power Generating Module.

ECC.A.6.2.8.2 The performance of the Over-Excitation Limiter, shall be demonstrated by testing as described in ECP.A.5.6. Any operation beyond the Over-Excitation Limit shall be controlled by the Over-Excitation Limiter or stator current limiter without the operation of any Protection that could trip the Onshore Synchronous Power Generating Module.

ECC.A.6.2.8.3 The EU Generator shall also make provision to prevent any over-excitation restriction of the Onshore Synchronous Generating Unit when the Excitation System is under manual control, other than that necessary to ensure the Onshore Power Generating Module is operating within its design limits.
APPENDIX E7 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR AC CONNECTED ONSHORE POWER PARK MODULES AND OTSDUW PLANT AND APPARATUS AT THE INTERFACE POINT HVDC SYSTEMS AND REMOTE END HVDC CONVERTER STATIONS

ECC.A.7.1 Scope
ECC.A.7.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for Onshore Power Park Modules, Onshore HVDC Converters, Remote End HVDC Converter Stations and OTSDUW Plant and Apparatus at the Interface Point that must be complied with by the User. This Appendix does not limit any site specific requirements where in The Company’s reasonable opinion these facilities are necessary for system reasons. The control performance requirements applicable to Configuration 2 AC Connected Offshore Power Park Modules and Configuration 2 DC Connected Power Park Modules are defined in Appendix E8.

ECC.A.7.1.2 Proposals by EU Generators or HVDC System Owners to make a change to the voltage control systems are required to be notified to The Company under the Planning Code (PC.A.1.2(b) and (c)) as soon as the Generator or HVDC System Owner anticipates making the change. The change may require a revision to the Bilateral Agreement.

ECC.A.7.1.3 In the case of a Remote End HVDC Converter at a HVDC Converter Station, the control performance requirements shall be specified in the Bilateral Agreement. These requirements shall be consistent with those specified in ECC.6.3.2. In the case where the Remote End HVDC Converter is required to ensure the zero transfer of Reactive Power at the HVDC Interface Point then the requirements shall be specified in the Bilateral Agreement which shall be consistent with those requirements specified in ECC.A.8. In the case where a wider reactive capability has been specified in ECC.6.3.2.4, then the requirements consistent with those specified in ECC.A.7.2 shall apply with any variations being agreed between the User and The Company.

ECC.A.7.2 Requirements
ECC.A.7.2.1 The Company requires that the continuously acting automatic voltage control system for the Onshore Power Park Module, Onshore HVDC Converter or OTSDUW Plant and Apparatus shall meet the following functional performance specification. If a Network Operator has confirmed to The Company that its network to which an Embedded Onshore Power Park Module or Onshore HVDC Converter or OTSDUW Plant and Apparatus is connected is restricted such that the full reactive range under the steady state voltage control requirements (ECC.A.7.2.2) cannot be utilised, The Company may specify alternative limits to the steady state voltage control range that reflect these restrictions. Where the Network Operator subsequently notifies The Company that such restriction has been removed, The Company may propose a Modification to the Bilateral Agreement (in accordance with the CUSC contract) to remove the alternative limits such that the continuously acting automatic voltage control system meets the following functional performance specification. All other requirements of the voltage control system will remain as in this Appendix.

ECC.A.7.2.2 Steady State Voltage Control
ECC.A.7.2.2.1 The Onshore Power Park Module, Onshore HVDC Converter or OTSDUW Plant and Apparatus shall provide continuous steady state control of the voltage at the Onshore Grid Entry Point (or Onshore User System Entry Point if Embedded) (or the Interface Point in the case of OTSDUW Plant and Apparatus ) with a Setpoint Voltage and Slope characteristic as illustrated in Figure ECC.A.7.2.2a.
ECC.A.7.2.2.2 The continuously acting automatic control system shall be capable of operating to a Setpoint Voltage between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt values of 95%, 95.25%, 95.5% ... may be specified, but not intermediate values. The initial Setpoint Voltage will be 100%. The tolerance within which this Setpoint Voltage shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. The Company may request the EU Generator or HVDC System Owner to implement an alternative Setpoint Voltage within the range of 95% to 105%. For Embedded Generators and Embedded HVDC System Owners the Setpoint Voltage will be discussed between The Company and the relevant Network Operator and will be specified to ensure consistency with ECC.6.3.4.

ECC.A.7.2.2.3 The Slope characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial Slope setting will be 4%. The tolerance within which this Slope shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a Slope setting of 4%, the achieved value shall be between 3.5% and 4.5%. The Company may request the EU Generator or HVDC System Owner to implement an alternative slope setting within the range of 2% to 7%. For Embedded Generators and Onshore Embedded HVDC Converter Station Owners the Slope setting will be discussed between The Company and the relevant Network Operator and will be specified to ensure consistency with ECC.6.3.4.
Figure ECC.A.7.2.2b shows the required envelope of operation for OTSDUW Plant and Apparatus, Onshore Power Park Modules and Onshore HVDC Converters except for those Embedded at 33kV and below or directly connected to the National Electricity Transmission System at 33kV and below. Figure ECC.A.7.2.2c shows the required envelope of operation for Onshore Power Park Modules Embedded at 33kV and below, or directly connected to the National Electricity Transmission System at 33kV and below. The enclosed area within points ABCDEFGH is the required capability range within which the Slope and Setpoint Voltage can be changed.
ECC.A.7.2.2.5 Should the operating point of the, OTSDUW Plant and Apparatus or Onshore Power Park Module, or Onshore HVDC Converter deviate so that it is no longer a point on the operating characteristic (figure ECC.A.7.2.2a) defined by the target Setpoint Voltage and Slope, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.

ECC.A.7.2.2.6 Should the Reactive Power output of the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter reach its maximum lagging limit at a Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded (or Interface Point in the case of OTSDUW Plant and Apparatus ) above 95%, the OTSDUW Plant and Apparatus or Onshore Power Park Module or HVDC System shall maintain maximum lagging Reactive Power output for voltage reductions down to 95%. This requirement is indicated by the line EF in figures ECC.A.7.2.2b and ECC.A.7.2.2c as applicable. Should the Reactive Power output of the OTSDUW Plant and Apparatus or Onshore Power Park Module, or Onshore HVDC Converter reach its maximum leading limit at a Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus ) below 105%, the OTSDUW Plant and Apparatus or Onshore Power Park Module, or Onshore HVDC Converter shall maintain maximum leading Reactive Power output for voltage increases up to 105%. This requirement is indicated by the line AB in figures ECC.A.7.2.2b and ECC.A.7.2.2c as applicable.

ECC.A.7.2.2.7 For Onshore Grid Entry Point voltages (or Onshore User System Entry Point voltages if Embedded-or Interface Point voltages) below 95%, the lagging Reactive Power capability of the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converters should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures ECC.A.7.2.2b and ECC.A.7.2.2c. For Onshore Grid Entry Point voltages (or User System Entry Point voltages if Embedded or Interface Point voltages) above 105%, the leading Reactive Power capability of the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC System Converter should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures ECC.A.7.2.2b and ECC.A.7.2.2c as applicable. Should the Reactive Power output of the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter reach its maximum lagging limit at an Onshore Grid Entry Connection Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point in the case of OTSDUW Plant and Apparatus) below 95%, the Onshore Power Park Module, Onshore HVDC Converter shall maintain maximum lagging reactive current output for further voltage decreases. Should the Reactive Power output of the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter reach its maximum leading limit at a Onshore Grid Entry Point voltage (or User System Entry Point voltage if Embedded or Interface Point in the case of an OTSDUW Plant and Apparatus) above 105%, the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.7.2.2.8 All OTSDUW Plant and Apparatus must be capable of enabling EU Code Users undertaking OTSDUW to comply with an instruction received from The Company relating to a variation of the Setpoint Voltage at the Interface Point within 2 minutes of such instruction being received.

ECC.A.7.2.2.9 For OTSDUW Plant and Apparatus connected to a Network Operator's System where the Network Operator has confirmed to The Company that its System is restricted in accordance with ECC.A.7.2.1, clause ECC.A.7.2.2.8 will not apply unless The Company can reasonably demonstrate that the magnitude of the available change in Reactive Power has a significant effect on voltage levels on the Onshore National Electricity Transmission System.

ECC.A.7.2.3 Transient Voltage Control
ECC.A.7.2.3.1 For an on-load step change in Onshore Grid Entry Point or Onshore User System Entry Point voltage, or in the case of OTSDUW Plant and Apparatus an on-load step change in Transmission Interface Point voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the Reactive Power output response of the, OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVARs seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure ECC.A.7.2.3.1a.

(ii) the response shall be such that 90% of the change in the Reactive Power output of the, OTSDUW Plant and Apparatus or Onshore Power Park Module, or Onshore HVDC Converter will be achieved within

- 2 seconds, where the step is sufficiently large to require a change in the steady state Reactive Power output from its maximum leading value to its maximum lagging value or vice versa and
- 1 second where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value as required by ECC.6.3.2 (or, if appropriate ECC.A.7.2.2.6 or ECC.A.7.2.2.7);

(iii) the magnitude of the Reactive Power output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within 5 seconds from achieving 90% of the response as defined in ECC.A.7.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum Reactive Power.

(v) following the transient response, the conditions of ECC.A.7.2.2 apply.

\[\text{Figure ECC.A.7.2.3.1a}\]

ECC.A.7.2.3.2 OTSDUW Plant and Apparatus or Onshore Power Park Modules or Onshore HVDC Converters shall be capable of

(a) changing its Reactive Power output from its maximum lagging value to its maximum
leading value, or vice versa, then reverting back to the initial level of Reactive Power output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing its Reactive Power output from zero to its maximum leading value then reverting back to zero Reactive Power output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero Reactive Power output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to The Company in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to ECC.A.7.2.3.1 where the change in Reactive Power output is in response to an on-load step change in Onshore Grid Entry Point or Onshore User System Entry Point voltage, or in the case of OTSDUW Plant and Apparatus an on-load step change in Transmission Interface Point voltage.

ECC.A.7.2.4 Power Oscillation Damping

ECC.A.7.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a Power System Stabiliser (PSS) shall be specified if, in The Company's view, this is required for system reasons. However if a Power System Stabiliser is included in the voltage control system its settings and performance shall be agreed with The Company and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the Generator will provide to The Company a report covering the areas specified in ECP.A.3.2.2.

ECC.A.7.2.5 Overall Voltage Control System Characteristics

ECC.A.7.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in Onshore Grid Entry Point voltage (or Onshore User System Entry Point voltage if Embedded or Interface Point voltage in the case of OTSDUW Plant and Apparatus).

ECC.A.7.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the OTSDUW Plant and Apparatus or Onshore Power Park Module or Onshore HVDC Converter should also meet this requirement.

ECC.A.7.2.5.3 The response of the voltage control system (including the Power System Stabiliser if employed) shall be demonstrated by testing in accordance with ECP.A.6.

ECC.A.7.3 Reactive Power Control

ECC.A.7.3.1 As defined in ECC.6.3.8.3.4, Reactive Power control mode of operation is not required in respect of Onshore Power Park Modules or OTSDUW Plant and Apparatus or Onshore HVDC Converters unless otherwise specified by The Company in coordination with the relevant Network Operator. However where there is a requirement for Reactive Power control mode of operation, the following requirements shall apply.

ECC.A.7.3.2 The Onshore Power Park Module or OTSDUW Plant and Apparatus or Onshore HVDC Converter shall be capable of setting the Reactive Power setpoint anywhere in the Reactive Power range as specified in ECC.6.3.2.4 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full Reactive Power, controlling the reactive power at the Grid Entry Point or User System Entry Point if Embedded to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full Reactive Power.

ECC.A.7.3.3 Any additional requirements for Reactive Power control mode of operation shall be specified
by The Company in coordination with the relevant Network Operator.

ECC.A.7.4 Power Factor Control

ECC.A.7.4.1 As defined in ECC.6.3.8.4.3, Power Factor control mode of operation is not required in respect of Onshore Power Park Modules or OTSDUW Plant and Apparatus or Onshore HVDC Converters unless otherwise specified by The Company in coordination with the relevant Network Operator. However where there is a requirement for Power Factor control mode of operation, the following requirements shall apply.

ECC.A.7.4.2 The Onshore Power Park Module or OTSDUW Plant and Apparatus or Onshore HVDC Converter shall be capable of controlling the Power Factor at the Grid Entry Point or User System Entry Point (if Embedded) within the required Reactive Power range as specified in ECC.6.3.2.2.1 and ECC.6.3.2.4 to a specified target Power Factor. The Company shall specify the target Power Factor value (which shall be achieved within 0.01 of the set Power Factor), its tolerance and the period of time to achieve the target Power Factor following a sudden change of Active Power output. The tolerance of the target Power Factor shall be expressed through the tolerance of its corresponding Reactive Power. This Reactive Power tolerance shall be expressed by either an absolute value or by a percentage of the maximum Reactive Power of the Onshore Power Park Module or OTSDUW Plant and Apparatus or Onshore HVDC Converter. The details of these requirements being pursuant to the terms of the Bilateral Agreement.

ECC.A.7.4.3 Any additional requirements for Power Factor control mode of operation shall be specified by The Company in coordination with the relevant Network Operator.
APPENDIX E8 - PERFORMANCE REQUIREMENTS FOR CONTINUOUSLY ACTING AUTOMATIC VOLTAGE CONTROL SYSTEMS FOR CONFIGURATION 2 AC CONNECTED OFFSHORE POWER PARK MODULES AND CONFIGURATION 2 DC CONNECTED POWER PARK MODULES

ECC.A.8.1 Scope

ECC.A.8.1.1 This Appendix sets out the performance requirements of continuously acting automatic voltage control systems for Configuration 2 AC Connected Offshore Power Park Modules and Configuration 2 DC Connected Power Park Modules that must be complied with by the EU Code User. This Appendix does not limit any site specific requirements that may be specified where in The Company's reasonable opinion these facilities are necessary for system reasons.

ECC.A.8.1.2 These requirements also apply to Configuration 2 DC Connected Power Park Modules. In the case of a Configuration 1 DC Connected Power Park Module the technical performance requirements shall be specified by The Company. Where the EU Generator in respect of a DC Connected Power Park Module has agreed to a wider reactive capability range as defined under ECC.6.3.2.5 and ECC.6.2.3.6 then the requirements that apply will be specified by The Company and which shall reflect the performance requirements detailed in ECC.A.8.2 below but with different parameters such as droop and Setpoint Voltage.

ECC.A.8.1.3 Proposals by EU Generators to make a change to the voltage control systems are required to be notified to The Company under the Planning Code (PC.A.1.2(b) and (c)) as soon as the Generator anticipates making the change. The change may require a revision to the Bilateral Agreement.

ECC.A.8.2 Requirements

ECC.A.8.2.1 The Company requires that the continuously acting automatic voltage control system for the Configuration 2 AC connected Offshore Power Park Module and Configuration 2 DC Connected Power Park Module shall meet the following functional performance specification.

ECC.A.8.2.2 Steady State Voltage Control

ECC.A.8.2.2.1 The Configuration 2 AC connected Offshore Power Park Module and Configuration 2 DC Connected Power Park Module shall provide continuous steady state control of the voltage at the Offshore Connection Point with a Setpoint Voltage and Slope characteristic as illustrated in Figure ECC.A.8.2.2a.

![Figure ECC.A.8.2.2a](image-url)
ECC.A.8.2.2.2 The continuously acting automatic control system shall be capable of operating to a **Setpoint Voltage** between 95% and 105% with a resolution of 0.25% of the nominal voltage. For the avoidance of doubt values of 95%, 95.25%, 95.5% ... may be specified, but not intermediate values. The initial **Setpoint Voltage** will be 100%. The tolerance within which this **Setpoint Voltage** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.25% and a Setpoint Voltage of 100%, the achieved value shall be between 99.75% and 100.25%. **The Company** may request the **EU Generator** to implement an alternative **Setpoint Voltage** within the range of 95% to 105%.

ECC.A.8.2.2.3 The **Slope** characteristic of the continuously acting automatic control system shall be adjustable over the range 2% to 7% (with a resolution of 0.5%). For the avoidance of doubt values of 2%, 2.5%, 3% may be specified, but not intermediate values. The initial **Slope** setting will be 4%. The tolerance within which this **Slope** shall be achieved is specified in BC2.A.2.6. For the avoidance of doubt, with a tolerance of 0.5% and a **Slope** setting of 4%, the achieved value shall be between 3.5% and 4.5%. **The Company** may request the **EU Generator** to implement an alternative slope setting within the range of 2% to 7%.

ECC.A.8.2.2.4 Figure ECC.A.8.2.2b shows the required envelope of operation for Configuration 2 AC connected Offshore Power Park Module and Configuration 2 DC Connected Power Park Module. The enclosed area within points ABCDEFGH is the required capability range within which the **Slope** and **Setpoint Voltage** can be changed.

ECC.A.8.2.2.5 Should the operating point of the Configuration 2 AC connected Offshore Power Park or Configuration 2 DC Connected Power Park Module deviate so that it is no longer a point on the operating characteristic (Figure ECC.A.8.2.2a) defined by the target **Setpoint Voltage** and **Slope**, the continuously acting automatic voltage control system shall act progressively to return the value to a point on the required characteristic within 5 seconds.
ECC.A.8.2.2.6 Should the Reactive Power output of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module reach its maximum lagging limit at an Offshore Grid Entry Point or Offshore User System Entry Point or HVDC Interface Point voltage above 95%, the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module shall maintain maximum lagging Reactive Power output for voltage reductions down to 95%. This requirement is indicated by the line EF in figure ECC.A.8.2.2b. Should the Reactive Power output of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module reach its maximum leading limit at the Offshore Grid Entry Point or Offshore User System Entry Point or HVDC Interface Point voltage below 105%, the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module shall maintain maximum leading Reactive Power output for voltage increases up to 105%. This requirement is indicated by the line AB in figures ECC.A.8.2.2b.

ECC.A.8.2.2.7 For Offshore Grid Entry Point or User System Entry Point or HVDC Interface Point voltages below 95%, the lagging Reactive Power capability of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module should be that which results from the supply of maximum lagging reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line DE in figures ECC.A.8.2.2b. For Offshore Grid Entry Point or Offshore User System Entry Point voltages or HVDC Interface Point voltages above 105%, the leading Reactive Power capability of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module should be that which results from the supply of maximum leading reactive current whilst ensuring the current remains within design operating limits. An example of the capability is shown by the line AH in figures ECC.A.8.2.2b. Should the Reactive Power output of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module reach its maximum lagging limit at an Offshore Grid Entry Point or Offshore User System Entry voltage or HVDC Interface Point voltage below 95%, the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module shall maintain maximum lagging reactive current output for further voltage decreases. Should the Reactive Power output of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module reach its maximum leading limit at an Offshore Grid Entry Point or Offshore User System Entry voltage or HVDC Interface Point voltage above 105%, the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module shall maintain maximum leading reactive current output for further voltage increases.

ECC.A.8.2.3 Transient Voltage Control

ECC.A.8.2.3.1 For an on-load step change in Offshore Grid Entry Point or Offshore User System Entry Point voltage or HVDC Interface Point voltage, the continuously acting automatic control system shall respond according to the following minimum criteria:

(i) the Reactive Power output response of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module shall commence within 0.2 seconds of the application of the step. It shall progress linearly although variations from a linear characteristic shall be acceptable provided that the MVAR seconds delivered at any time up to 1 second are at least those that would result from the response shown in figure ECC.A.8.2.3.1a.

(ii) the response shall be such that 90% of the change in the Reactive Power output of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module will be achieved within

\[2 \text{ seconds, where the step is sufficiently large to require a change in the steady state Reactive Power output from its maximum leading value to its maximum lagging value or vice versa and}\]
- 1 second where the step is sufficiently large to require a change in the steady state Reactive Power output from zero to its maximum leading value or maximum lagging value as required by ECC.6.3.2 (or, if appropriate ECC.A.8.2.2.6 or ECC.A.8.2.2.7);

(iii) the magnitude of the Reactive Power output response produced within 1 second shall vary linearly in proportion to the magnitude of the step change.

(iv) within 5 seconds from achieving 90% of the response as defined in ECC.A.8.2.3.1 (ii), the peak to peak magnitude of any oscillations shall be less than 5% of the change in steady state maximum Reactive Power.

(v) following the transient response, the conditions of ECC.A.8.2.2 apply.

![Diagram](image)

**ECC.A.8.2.3.2**  
**Configuration 2 AC connected Offshore Power Park Module** or **Configuration 2 DC Connected Power Park Module** shall be capable of

(a) changing their Reactive Power output from maximum lagging value to maximum leading value, or vice versa, then reverting back to the initial level of Reactive Power output once every 15 seconds for at least 5 times within any 5 minute period; and

(b) changing Reactive Power output from zero to maximum leading value then reverting back to zero Reactive Power output at least 25 times within any 24 hour period and from zero to its maximum lagging value then reverting back to zero Reactive Power output at least 25 times within any 24 hour period. Any subsequent restriction on reactive capability shall be notified to The Company in accordance with BC2.5.3.2, and BC2.6.1.

In all cases, the response shall be in accordance to ECC.A.8.2.3.1 where the change in Reactive Power output is in response to an on-load step change in Offshore Grid Entry Point or Offshore User System Entry Point voltage or HVDC Interface Point voltage.

**ECC.A.8.2.4**  
**Power Oscillation Damping**
ECC.A.8.2.4.1 The requirement for the continuously acting voltage control system to be fitted with a Power System Stabiliser (PSS) shall be specified if, in The Company’s view, this is required for system reasons. However if a Power System Stabiliser is included in the voltage control system its settings and performance shall be agreed with The Company and commissioned in accordance with BC2.11.2. To allow assessment of the performance before on-load commissioning the Generator or HVDC System Owner will provide to The Company a report covering the areas specified in ECP.A.3.2.2.

ECC.A.8.2.5 Overall Voltage Control System Characteristics

ECC.A.8.2.5.1 The continuously acting automatic voltage control system is required to respond to minor variations, steps, gradual changes or major variations in Offshore Grid Entry Point or Offshore User System Entry Point or HVDC Interface Point voltage.

ECC.A.8.2.5.2 The overall voltage control system shall include elements that limit the bandwidth of the output signal. The bandwidth limiting must be consistent with the speed of response requirements and ensure that the highest frequency of response cannot excite torsional oscillations on other plant connected to the network. A bandwidth of 0-5Hz would be judged to be acceptable for this application. All other control systems employed within the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module should also meet this requirement.

ECC.A.8.2.5.3 The response of the voltage control system (including the Power System Stabiliser if employed) shall be demonstrated by testing in accordance with ECP.A.6.

ECC.A.8.3 Reactive Power Control

ECC.A.8.3.1 Reactive Power control mode of operation is not required in respect of Configuration 2 AC connected Offshore Power Park Modules or Configuration 2 DC Connected Power Park Modules unless otherwise specified by The Company. However where there is a requirement for Reactive Power control mode of operation, the following requirements shall apply.

ECC.A.8.3.2 Configuration 2 AC connected Offshore Power Park Modules or Configuration 2 DC Connected Power Park Modules shall be capable of setting the Reactive Power setpoint anywhere in the Reactive Power range as specified in ECC.6.3.2.8.2 with setting steps no greater than 5 MVAr or 5% (whichever is smaller) of full Reactive Power, controlling the Reactive Power at the Offshore Grid Entry Point or Offshore User System Entry Point or HVDC Interface Point to an accuracy within plus or minus 5MVAr or plus or minus 5% (whichever is smaller) of the full Reactive Power.

ECC.A.8.3.3 Any additional requirements for Reactive Power control mode of operation shall be specified by The Company.

ECC.A.8.4 Power Factor Control

ECC.A.8.4.1 Power Factor control mode of operation is not required in respect of Configuration 2 AC connected Offshore Power Park Modules or Configuration 2 DC Connected Power Park Modules unless otherwise specified by The Company. However where there is a requirement for Power Factor control mode of operation, the following requirements shall apply.

ECC.A.8.4.2 Configuration 2 AC connected Offshore Power Park Modules or Configuration 2 DC Connected Power Park Modules shall be capable of controlling the Power Factor at the Offshore Grid Entry Point or Offshore User System Entry Point or HVDC Interface Point within the required Reactive Power range as specified in ECC.6.3.2.8.2 with a target Power Factor. The Company shall specify the target Power Factor (which shall be achieved to within 0.01 of the set Power Factor), its tolerance and the period of time to achieve the target Power Factor following a sudden change of Active Power output. The tolerance of the target Power Factor shall be expressed through the tolerance of its corresponding Reactive Power.
This Reactive Power tolerance shall be expressed by either an absolute value or by a percentage of the maximum Reactive Power of the Configuration 2 AC connected Offshore Power Park Module or Configuration 2 DC Connected Power Park Module. The details of these requirements being specified by The Company.

ECC.A.8.4.3 Any additional requirements for Power Factor control mode of operation shall be specified by The Company.

< END OF EUROPEAN CONNECTION CONDITIONS>
DEMAND RESPONSE SERVICES CODE  
(DRSC)

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PART I
INTRODUCTION

The Demand Response Services Code is concerned with Demand Response Providers who contract with The Company for the provision of Ancillary Services.

Ancillary Services are non-mandatory services used by The Company in operating the System. They are provided by Demand Response Providers with payment being dealt with under the terms of the relevant agreement for the Ancillary Service.

Where a Demand Response Provider is interested in offering an Ancillary Service to The Company, then further details and additional information of the Ancillary Services are available from the Balancing Services section of the Website.

Where The Company and a Demand Response Provider enter into an Ancillary Services agreement, it shall be in accordance with Transmission Licence condition C16 and the Standard Contract Terms.

The Demand Response Services Code which would form part of an Ancillary Services agreement between a Demand Response Provider and The Company and to discharge the obligations under Retained EU Law (Commission Regulation (EU) 2016/1388). The Ancillary Services agreement will include an obligation on the Demand Response Provider to satisfy the applicable requirements of this Demand Response Services Code.

The Demand Response Services Code applies only to Demand Response Providers who have entered into an agreement with The Company to provide an Ancillary Service. This Demand Response Services Code does not apply to Users who are not Demand Response Providers.

For the avoidance of doubt, Network Operators and Non Embedded Customers in respect of EU Grid Supply Points are required to satisfy the compliance requirements in section DRSC.11 of this code in addition to the European Compliance Processes only if they are also a Demand Response Provider.

OBJECTIVE

The objectives of the DRSC are to

Ensure the obligations of Retained EU Law (Commission Regulation (EU) 2016/1388) have been discharged; and

Complement the requirements of the Ancillary Services agreement between The Company and a Demand Response Provider; and

Define the minimum technical and compliance requirements Demand Response Providers are required to satisfy if they provide a Demand Response Service to The Company under an Ancillary Services agreement.

SCOPE

The DRSC applies to any Demand Response Provider who has entered into an agreement to provide Ancillary Services with The Company.

The DRSC does not apply to Users, BM Participants or other parties unless they are also a Demand Response Provider.

GENERAL PROVISIONS

Demand Response Services shall be based on the following categories.

(a) Controlled by instruction from The Company

(i) Demand Response Active Power Control

(ii) Demand Response Reactive Power Control

(iii) Demand Response Transmission Constraint Management
(b) Automatic operation once the facility has been instructed into operation upon instruction from The Company pursuant to the terms of the Ancillary Services agreement.

(i) Demand Response System Frequency Control

(ii) Demand Response Very Fast Active Power Control

**DRSC.4.2**

*Demand Response Providers* who own, operate, control or manage *Plant* and *Apparatus* or *Demand Unit(s)* within a *Demand Facility* and/or *Closed Distribution System(s)* or on an aggregated basis may provide *Demand Response Services* to *The Company*. *Demand Response Providers* can offer *Demand Response Services* on an individual or collective basis and increase or decrease their Demand in accordance with the terms of their Ancillary Services agreement.

**DRSC.4.3**

The *Demand Response Services* specified in DRSC.4.1 are not exclusive and do not preclude *Demand Response Providers* from negotiating other services with *The Company*. These services would be pursuant to the terms of the Ancillary Services agreement.

**DRSC.5**

SPECIFIC PROVISIONS FOR DEMAND UNITS WITH DEMAND RESPONSE ACTIVE POWER CONTROL AND TRANSMISSION CONSTRAINT MANAGEMENT

**DRSC.5.1**

Where a *Demand Response Provider* provides *Demand Response Active Power Control*, *Demand Response Reactive Power Control* or *Demand Response Transmission Constraint Management* to *The Company*, then the following requirements as detailed below shall apply. For the avoidance of doubt, these requirements shall apply either individually or where it is not part of a *Demand Facility*, collectively as part of a *Demand Aggregation* scheme through a *Demand Response Provider*. *Demand Response Providers* shall ensure that any *Demand Unit* which they own, operate, control or manage and which is used to provide *Demand Response Services* shall:

(a) Be capable of satisfying the *Frequency* range requirements as specified in ECC.6.1.2.1.

(b) Be capable of satisfying the voltage range requirements as specified in ECC.6.1.4.1.

(c) Be capable of controlling the power consumption from the *Total System* in accordance with the terms of the *Ancillary Services* agreement.

(d) Be capable of receiving instructions from *The Company* either directly or through a third party to modify their demand in accordance with the *Demand Response Service* they have agreed to provide.

(e) Be capable of adjusting its *Real Power* or *Reactive Power* flow within a time period pursuant to the terms of the *Ancillary Services* agreement.

(f) Be capable of full execution of an instruction issued by *The Company* to modify its power flow.

(g) Be capable of further demand changes as instructed by *The Company*, following the execution of a previous instruction issued by *The Company* in accordance with the Ancillary Services agreement. Any such instruction shall not exceed the normal safe operating conditions of the *Demand Response Provider’s Plant and Apparatus* or *Demand Unit(s)* which could cause such equipment to trip. Instructions to modify *Active Power* or *Reactive Power* flow may have immediate or delayed effects but in any event would need to comply with the requirements of the Ancillary Services agreement.

(h) Notify *The Company* of any change in the available capacity in accordance with the relevant Ancillary Services agreement.

(i) Be capable of withstanding a rate of change of *System Frequency* of up to a maximum of 1Hz/s measured over a 500ms time frame.
In addition to the requirements of DRSC.5.1, where a Demand Response Provider automatically modifies its Demand in response to changes in System Frequency or System voltage or both, The Company will have previously instructed the Demand Response Provider to switch these facilities into service in accordance with the terms of the Ancillary Services agreement prior to any automatic action taking place. The ability for The Company to issue instructions, receive acknowledgement of those instructions and receive operational metering data (for example voltage, current, Active Power and Reactive Power signals) from the Demand Response Provider will be dependent upon the type of Demand Response Service provided and shall be defined in the Ancillary Services agreement which shall be pursuant to the Standard Contract Terms.

Non Embedded Customers who are also Demand Response Provider’s shall be capable of providing Demand Response Reactive Power Control by switching static compensation equipment into or out of service.

Where a Demand Response Provider provides Demand Response System Frequency Control to The Company, then the following requirements as detailed below shall apply. For the avoidance of doubt, these requirements apply either individually or where it is not part of a Demand Facility, collectively as part of a Demand Aggregation scheme through a Demand Response Provider. Demand Response Providers shall ensure that any Plant and Apparatus or Demand Unit(s) which they own, operate, control or manage, and which is used to provide Demand Response System Frequency Control shall:-

(a) Be capable of satisfying the Frequency range requirements as specified in ECC.6.1.2.1.
(b) Be capable of satisfying the voltage range requirements as specified in ECC.6.1.4.1.
(c) Be fitted with a deadband facility no greater than 0.03Hz unless otherwise specified in the Ancillary Services agreement. This requirement shall not apply to Demand Response Providers where only a Non–Dynamic Frequency Response Service is provided.
(d) The envelope of operation of the Demand Response System Frequency Control shall be in accordance with the terms of the Ancillary Services agreement. For the avoidance of doubt, continuous operation would not be required in respect of a static Frequency response service.
(e) Be fitted with a control system which is capable of responding to changes in System Frequency outside the nominal value of 50Hz. A deadband either side of nominal Frequency shall be permitted which shall be in accordance with the requirement of the Ancillary Services agreement.
(f) Be equipped with a controller that measures the actual System Frequency. The refresh rate for this controller shall be no longer than 0.2 seconds.
(g) Be able to detect a change in System Frequency of 0.01Hz. Each Demand Unit owned, operated, controlled or managed by a Demand Response Provider shall be capable of a rapid detection and respond to changes in System Frequency which shall be pursuant to the terms of the Ancillary Services agreement. An offset in the steady state measurement of Frequency shall be acceptable up to 0.05Hz. Frequency measurements must be recorded at each Demand Facility and must not be derived on an aggregated basis.

SPECIFIC PROVISIONS FOR DEMAND UNITS WITH DEMAND RESPONSE VERY FAST ACTIVE POWER CONTROL

Where a Demand Response Provider provides Demand Response Very Fast Active Power Control to The Company, then the applicable requirements shall be pursuant to the terms of the Ancillary Services agreement which shall specify:-

(a) The relationship between the change in Active Power and the rate of change of System Frequency over the Demand range of the Demand Response Provider’s Demand Unit(s) which they own, operate, control or manage.
(b) The operating principles of the Demand Response Very Fast Active Power Control and associated performance parameters.

(c) The response time of the Demand Response Very Fast Active Power Control which shall be no longer than 2 seconds from the inception of the System Frequency change.

DRSC.8 DATA REQUIRED BY THE COMPANY FROM DEMAND RESPONSE PROVIDER'S

DRSC.8.1 The data required to be submitted to The Company by a Demand Response Provider will vary depending upon the type of Demand Response Service provided and will be set out in the Ancillary Services agreement.

DRSC.9 OPERATIONAL METERING REQUIREMENTS

DRSC.9.1 The operational metering data required to be submitted to The Company will vary depending upon the type of Demand Response Service provided. Demand Response Providers may be required to install such operational metering equipment in accordance with the Ancillary Services agreement.

DRSC.10 INSTRUCTIONS ISSUED TO DEMAND RESPONSE PROVIDER’S

DRSC.10.1 Demand Response Providers may be required to be fitted with communication and instruction facilities to enable The Company to instruct them in the operational timeframe. These requirements will vary depending upon the type of Demand Response Service provided and will be set out in the Ancillary Services agreement.

PART II

COMPLIANCE REQUIREMENTS FOR DEMAND RESPONSE SERVICES

DRSC.11 OPERATIONAL NOTIFICATION PROCEDURE

DRSC.11.1 General Provisions

DRSC.11.1.1 Demand Response Providers who enter into an agreement with The Company to provide Ancillary Services are required to undertake a compliance process to ensure the Plant and Apparatus or Demand Unit(s) which they own, operate, control or manage, satisfies the requirements of the Ancillary Services agreement and the Demand Response Services Code. For the avoidance of doubt, Demand Response Providers who are also EU Code Users, will also be required to satisfy the requirements of the applicable requirements of the European Compliance Processes (ECP’s).

DRSC.11.2 Each Demand Response Provider, shall confirm to The Company its ability to comply with the requirements of the Ancillary Services agreement.

DRSC.11.3 Each Demand Response Provider shall notify The Company of any change to the Plant or Apparatus which they own, operate, control or manage such they are no longer able to satisfy the conditions specified in the Ancillary Services agreement and/or the relevant provisions of the DRSC. Such changes shall be notified to The Company in accordance with the terms of the Ancillary Services agreement.

DRSC.11.2 Operational Notification Procedures for Demand Response Providers

DRSC.11.2.1 All Demand Response Providers are required to undertake an Operational Notification procedure which shall comprise a Demand Response Unit Document (DRUD).

DRSC.11.2.2 The format of the Demand Response Unit Document (DRUD) shall take the form shown...
in DRSC.A.1 and shall provide sufficient information to demonstrate the Plant and Apparatus or Demand Unit(s) which a Demand Response Provider owns, operates, controls or manages, is capable of satisfying the full requirements of the Ancillary Services agreement and the applicable requirements of the DRSC. The compliance requirements can be simplified to a single operational notification stage as well as be reduced as agreed with The Company. Demand Response Providers shall be required to submit a new DRUD for each subsequent Demand Unit added to its portfolio.

DRSC.11.2.3 When the Demand Response Provider has submitted a final DRUD to the satisfaction of The Company, which clearly demonstrates full compliance with the Ancillary Services agreement, The Company shall issue a Final Operational Notification to the Demand Response Provider.

DRSC.11.3 COMPLIANCE

DRSC.11.3.1 Responsibility of the Demand Response Provider

DRSC.11.3.1.1 Demand Response Providers are required to satisfy the requirements of the Ancillary Services agreement which shall include satisfying the applicable requirements of this Demand Response Services Code.

DRSC.11.3.1.2 Should the Demand Response Provider wish to modify the technical capability of the Plant and Apparatus or Demand Unit(s) which it owns, operates, controls or manages and which affects its compliance with the Ancillary Services agreement, it should notify and agree any timescales for the change with The Company prior to making any change.

DRSC.11.3.1.3 Any operational incidents or failure of the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by the Demand Response Provider which impacts its ability to satisfy the compliance requirements detailed in this Demand Response Services Code shall be notified to The Company as soon as possible after occurrence of the incident.

DRSC.11.3.1.4 Any planned test schedules and procedures to verify compliance of the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by the Demand Response Provider shall be submitted to The Company in advance of the tests. The Company shall assess the test schedules and procedures in a timely manner prior to agreeing that the Demand Response Provider can carry out the tests.

DRSC.11.3.1.5 The Company may witness such tests and record the performance of the Plant and Apparatus owned, operated, controlled or managed by the Demand Response Provider to verify compliance with the Ancillary Services agreement and the Demand Response Services Code.

DRSC.11.3.2 Role of The Company

DRSC.11.3.2.1 The Company shall assess the compliance of the Demand Response Provider and shall undertake monitoring throughout the life time of the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by the Demand Response Provider to ensure compliance with the requirements of the Ancillary Services agreement. The Company shall inform the Demand Response Provider of the outcome of such assessment.

DRSC.11.3.2.2 The Company may require Demand Response Providers to carry out compliance tests and simulations according to a repeat plan or general scheme or replacement of equipment which may have an impact on the compliance of the Plant and Apparatus or Demand Units owned, operated, controlled or managed by the Demand Response Provider as detailed in DRSC.11.3.1.3 and DRSC.11.3.1.4. The Company shall inform the Demand Response Provider of the results of these tests.
As part of this compliance process, the Demand Response Provider shall provide the following items:-

(a) Relevant documentation and certificates associated with the compliance process.
(b) Details of the technical data required to ensure compliance with the Ancillary Services agreement.
(c) Steady state and dynamic models (as applicable) of their Demand Units or Plant and Apparatus (or equivalent) as required and agreed with The Company.
(d) Timelines for the submission of system data required to perform System studies.
(e) Study results showing the expected steady state and dynamic performance of the Plant and Apparatus or Demand Unit(s) or the performance of their Demand Response Service on an aggregated basis as required and agreed with The Company.
(f) Submission of registered Equipment Certificates or otherwise as agreed with The Company.
(g) Conditions and procedures for the use of relevant Equipment Certificates issued by an Authorised Certifier to a Demand Response Provider or equivalent to the satisfaction of The Company.

If compliance tests or simulations cannot be carried out as agreed between the Demand Response Provider and The Company due to reasons attributable to The Company, then The Company shall not unreasonably withhold the Operational Notification referred to in DRSC.11.2.3.

The purpose of compliance testing is to ensure that the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by a Demand Response Provider is capable of satisfying the requirements of the Ancillary Services agreement and applicable sections of this Demand Response Services Code in addition to verifying that the models and data submitted provide a true and accurate representation of the Plant as built.

Notwithstanding the minimum requirements for compliance testing detailed in DRSC.11.4 of this Demand Response Services Code, The Company shall:-

(a) Allow the Demand Response Provider to carry out an alternative set of tests provided that they are efficient and sufficient to demonstrate that the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by a Demand Response Provider is capable of satisfying the requirements of the Ancillary Services agreement and the applicable sections of the Demand Response Services Code.

(b) Require the Demand Response Provider to carry out additional or alternative tests (where reasonable) to those specified in DRSC.11.5 where they would otherwise be insufficient to demonstrate compliance with the Ancillary Services agreement.

(c) Require the Demand Response Provider to be responsible for carrying out the tests in accordance with the requirements specified in DRSC.11.4 and DRSC.11.5 of the Demand Response Services Code. The Company shall cooperate with the Demand Response Provider and will not unduly delay the scheduling of the tests.

The Company may witness such tests (either on site or remotely from The Company’s control room) to record the performance of the Demand Response Providers
capability to verify compliance with the **Ancillary Services** agreement and the **Demand Response Services Code**. Where **The Company** witnesses the tests remotely, the **Demand Response Provider** shall provide the monitoring equipment necessary to record all relevant test signals and measurements in addition to ensuring that necessary representatives from the **Demand Response Provider** are available on site for the entire testing period. Signals specified by **The Company** shall be provided, if for selected tests, **The Company** wishes to use its own equipment to record performance. **The Company** will inform the **Demand Response Provider** if it wishes to witness the tests.

**DRSC.11.5** Compliance Testing for Demand Response Providers with Demand Response Active Power Control, Reactive Power Control and Transmission Constraint Management.

**DRSC.11.5.1** Demand Modification Tests

**DRSC.11.5.1.1** Demand Response Providers who have signed an **Ancillary Services** agreement with **The Company** to provide Demand Response Active Power Control, Demand Response Reactive Power Control or Demand Response Transmission Constraint Management, are required to demonstrate (through site tests) the capability of the **Plant** and **Apparatus** or **Demand Unit(s)** they own, operate, control or manage to satisfy the requirements of the **Ancillary Services** agreement and the applicable requirements of DRSC.5. The site tests should demonstrate the capability of the **Demand Response Providers** ability to operate with instruction over the agreed timeframes, Demand range and duration pursuant to the terms of the **Ancillary Services** agreement. The tests can be completed individually or as part of a **Demand** aggregation scheme.

**DRSC.11.5.1.2** The tests shall be carried out either by instruction from **The Company’s Control Centre** or by site tests through injections applied to the **Plant** and **Apparatus** or **Demand Unit(s)** owned, operated, controlled or managed by the **Demand Response Provider**.

**DRSC.11.5.1.3** The test shall be deemed as passed if the requirements of the **Ancillary Services** agreement have been satisfied and the applicable requirements of DRSC.5 demonstrated to the satisfaction of **The Company**.

**DRSC.11.5.1.4** A list of references to **Equipment Certificates** issued by an **Authorised Certifier** (or otherwise) as agreed with **The Company**, which can be supplied by the **Demand Response Provider** to demonstrate part of the evidence of compliance;

**DRSC.11.5.2** Disconnection and Reconnection of Static Compensation Facilities

**DRSC.11.5.2.1** Demand Response Providers who have signed an **Ancillary Services** agreement with **The Company** to provide Demand Response Active Power Control, Demand Response Reactive Power Control or Demand Response Transmission Constraint Management and have also agreed to disconnect or reconnect (or both) static compensation facilities when receiving an instruction from **The Company** in accordance with the requirements of the **Ancillary Services** agreement and DRSC.5.3, shall be required to demonstrate the performance of the **Plant** and **Apparatus** or **Demand Unit(s)** they own, operate, control or manage to satisfy these requirements. These requirements can be demonstrated individually or collectively as part of a demand aggregation scheme.

**DRSC.11.5.2.2** The tests shall be carried out either by instruction from **The Company’s Control Centre** or by site tests resulting in the disconnection and subsequent re-connection of the static compensation facilities.

**DRSC.11.5.2.3** The test shall be deemed as passed if the requirements of the **Ancillary Services** agreement have been satisfied and the applicable requirements of DRSC.5.3 demonstrated to the satisfaction of **The Company**.
DRSC.11.6 Compliance Simulation

DRSC.11.6.1 Common Provisions on Compliance Simulations

DRSC.11.6.1.1 Demand Response Providers who agree to provide Demand Response Very Fast Active Power Control are required to demonstrate their ability to satisfy the requirements of the Ancillary Services agreement and DRSC.7 through necessary simulation studies to the satisfaction of The Company.

DRSC.11.6.1.2 Demand Response Providers who have contracted to provide a Demand Response Very Fast Active Power Control service, are required to submit further simulation studies where there has been a development, replacement or modernisation of the Plant and Apparatus or Demand Unit(s), owned, operated, controlled or managed by the Demand Response Provider, or The Company has identified a non–compliance with the Demand Response Provider's ability to satisfy the requirements of the Ancillary Services agreement or DRSC.7.

DRSC.11.6.1.3 Notwithstanding the requirements of DRSC.11.6.1.1 and DRSC.11.6.1.2 The Company shall be entitled to:-

(a) Allow the Demand Response Provider to carry out an alternative set of simulations provided that they are efficient and sufficient to demonstrate that the Plant and Apparatus or Demand Unit(s) owned, operated, controlled or managed by the Demand Response Provider is capable of satisfying the requirements of the Ancillary Services agreement and the applicable sections of the Demand Response Services Code.

(b) Require the Demand Response Provider to carry out additional or alternative simulations to those specified in DRSC11.6.1.1 and DRSC.11.6.1.2 where they would otherwise be insufficient to demonstrate compliance with the Ancillary Services agreement.

DRSC.11.6.1.4 The Company may check that the Demand Response Provider complies with the requirements of the Ancillary Services agreement and the applicable sections of the Demand Response Services Code by carrying out its own compliance simulations based on the simulation reports, models and test measurements.

DRSC.11.6.1.5 The Company will supply upon request from the Demand Response Provider, data to enable the Demand Response Provider to carry out the required simulations in accordance with the requirements of the Ancillary Services agreement and DRSC.11.6.

DRSC.11.7 Additional Testing requirements for Non-Embedded Customers and CUSC Parties who are also Demand Response Providers

DRSC.11.7.1 Non-Embedded Customers and CUSC Parties who are also Demand Response Providers shall be required to execute a demand modification test after two consecutive unsuccessful responses in the operational environment or at least every year as agreed with The Company.

DRSC.11.7.2 Each Non-Embedded Customer and CUSC Party who are also Demand Response Providers and provide demand response low frequency demand disconnection shall execute a low frequency demand disconnection test at least once every three years.
## Demand Response Unit Document (DRUD)

### Statement of Compliance for Demand Response Providers

#### Contract company details

<table>
<thead>
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<th>Contracted company name</th>
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<tr>
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#### Demand Response Service Details

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<td>Type of Demand Response Service type, Asset type, Unit make up</td>
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<td>Aggregation methodology (if appropriate)</td>
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<td>Equipment Certificates (as applicable)</td>
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<td>Unit location/ connection point / ID</td>
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<td>Service start date</td>
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<td>Desired test date</td>
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<td>All documentation and certificates demonstrating compliance with the DRSC.</td>
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<td>Details of the technical data required to ensure compliance with the Ancillary Services agreement.</td>
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<td>Steady state and dynamic models (or equivalent information) of Plant and Apparatus or Demand Unit(s).</td>
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<td>Timelines for the submission of system studies or equivalent data.</td>
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<td>Study results showing the expected steady state and dynamic performance of the Plant and Apparatus or Demand Unit(s)</td>
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<tr>
<td>Conditions and procedures including the scope for registering Equipment Certificates or otherwise as agreed with The Company.</td>
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<td>Conditions and procedures for the use of relevant Equipment Certificates issued by an Authorised Certifier to a Demand Response Provider.</td>
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<td>Operational Metering Data to be submitted in accordance with Ancillary Services agreement.</td>
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<td>Ability to receive instructions to and from The Company accordance with the Ancillary Services agreement.</td>
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<td>DRSC Requirement</td>
<td>Compliance Y/N</td>
<td>Demand Response Provider Statement</td>
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<tr>
<td>Ability to operate over <strong>Frequency</strong> range as specified in DRSC.5.1(a).</td>
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<td>Ability to operate over voltage range as specified in DRSC.5.1(b).</td>
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<td>Ability to withstand a rate of change of system frequency up to a maximum of 1Hz per second as measured over a 500ms timeframe as specified in DRSC.5.1(i).</td>
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<td><strong>Non-Embedded Customers</strong> who are also <strong>Demand Response Providers</strong> ability to switch static compensation equipment into or out of service in accordance with DRSC5.3 as applicable.</td>
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<tr>
<td>Control system block diagrams, parameters and settings as applicable.</td>
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**Declaration**

Declaration – to be completed by Customer or the Demand Response Provider’s appointed technical representative

I declare that for all the Demand Response Provider’s information associated with this contract:

1. Compliance with the requirements of the Demand Response Services Code is achieved.
2. The commissioning checks have been successfully completed.

Name:
Signature:
Company Name:
Position:

Declaration – to be completed by The Company Witnessing Representative if applicable. Delete if not witnessed by the The Company.

I confirm that I have witnessed the commissioning checks in this document on behalf of

______________________________ and that the results are an accurate record of the checks

Name:
Signature:
Company Name:

< END OF DEMAND RESPONSE SERVICES CODE >
COMPLIANCE PROCESSES
(CP)

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INTRODUCTION

CP.1.1 The Compliance Processes ("CP") specifies:

- The process (leading to an Energisation Operational Notification) which must be followed by The Company and any GB Code User to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus (including OTSUA) prior to the relevant Plant and Apparatus (including any OTSUA) being energised.

- The process (leading to an Interim Operational Notification and Final Operational Notification) which must be followed by The Company and any Generator or DC Converter Station owner to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus (including any dynamically controlled OTSUA). This process shall be followed prior to and during the course of the relevant Plant and Apparatus (including OTSUA) being energised and Synchronised.

- The process (leading to a Limited Operational Notification) which must be followed by The Company and each Generator and DC Converter Station owner where any of its Plant and/or Apparatus (including any OTSUA) becomes unable to comply with relevant provisions of the Grid Code, and where applicable with Appendices F1 to F5 (and in the case of OTSUA, Appendices OF1 to OF5 of the Bilateral Agreement). This process also includes when changes or Modifications are made to Plant and/or Apparatus (including OTSUA). This process applies to such Plant and/or Apparatus after the Plant and/or Apparatus has become Operational and untilDisconnected from the Total System, (or until, in the case of OTSUA, the OTSUA Transfer Time), when changes or Modifications are made.

CP.1.2 As used in this CP, references to OTSUA means OTSUA to be connected or connected to the National Electricity Transmission System prior to the OTSUA Transfer Time.

CP1.3 Where the Generator or DC Convertor Station Owner and/or The Company are required to apply for a derogation from the Authority, this is not in respect of the OTSUA.

OBJECTIVE

CP.2.1 The objective of the CP is to ensure that there is a clear and consistent process for demonstration of compliance by GB Code Users with the Connection Conditions and Bilateral Agreement which are similar for all GB Code Users of an equivalent category and will enable The Company to comply with its statutory and Transmission Licence obligations.

CP.2.2 Provisions of the CP which apply in relation to OTSDUW and OTSUA shall (in any particular case) apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply.

CP.2.3 In relation to OTSDUW, provisions otherwise to be contained in a Bilateral Agreement may be contained in the Construction Agreement, and accordingly a reference in the CP to a relevant Bilateral Agreement includes the relevant Construction Agreement.

SCOPE

CP.3.1 The CP applies to The Company and to GB Code Users, which in the CP means:

(a) GB Generators (other than in relation to Embedded Small Power Stations or Embedded Medium Power Stations not subject to a Bilateral Agreement) including those undertaking OTSDUW.

(b) Network Operators;

(c) Non-Embedded Customers;

(d) DC Converter Station owners (other than those which only have Embedded DC Converter Stations not subject to a Bilateral Agreement).
CP.3.2 The above categories of GB Code User will become bound by the CP prior to them generating, distributing, supplying or consuming, or in the case of OTSUA, transmitting, as the case may be, and references to the various categories should, therefore, be taken as referring to them in that prospective role as well as to Users actually connected.

CP3.3 This CP does not apply to EU Code Users for whom the requirements of the ECP applies.

CP.4 CONNECTION PROCESS

CP.4.1 The CUSC Contract(s) contain certain provisions relating to the procedure for connection to the National Electricity Transmission System or, in the case of Embedded Power Stations or Embedded DC Converter Stations, becoming operational and include provisions to be complied with by GB Code Users prior to and during the course of The Company notifying the User that it has the right to become operational. In addition to such provisions, this CP sets out in further detail the processes to be followed to demonstrate compliance. Whilst this CP does not expressly address the processes to be followed in the case of OTSUA connecting to a Network Operator's User System prior to the OTSUA Transfer Time, the processes to be followed by The Company and the Generator in respect of OTSUA in such circumstances shall be consistent with those set out below by reference OTSUA directly connected to the National Electricity Transmission System.

CP.4.2 The provisions contained in CP.5 to CP.7 detail the process to be followed in order for the GB Code User’s Plant and Apparatus (including OTSUA) to become operational. This process includes EON (energisation) ION (interim synchronising) and FON (final).

CP.4.2.1 The provisions contained in CP.5 relate to the connection and energisation of User’s Plant and Apparatus (including OTSUA) to the National Electricity Transmission System or where Embedded, to a User’s System and is shown diagrammatically at CP.A.1.1.

CP.4.2.2 The provisions contained in CP.6 and CP.7 provide the process for Generators and DC Converter Station owners to demonstrate compliance with the Grid Code and with, where applicable, the CUSC Contract(s) prior to and during the course of such Generator’s or DC Converter Station owner’s Plant and Apparatus (including OTSUA up to the OTSUA Transfer Time) becoming operational and is shown diagrammatically at CP.A.1.2 and CP.A.1.3.

CP.4.2.3 The provisions contained in CP.8 detail the process to be followed when:

(a) a Generator or DC Converter Station owner’s Plant and/or Apparatus (including the OTSUA) is unable to comply with any provisions of the Grid Code and Bilateral Agreement; or,

(b) following any notification by a Generator or a DC Converter Station owner under the PC of any change to its Plant and Apparatus (including any OTSUA); or,

(c) a Modification to a Generator or a DC Converter Station owner’s Plant and/or Apparatus.

The process is shown diagrammatically at Appendix CP.A.1.4 for condition (a) and Appendix CP.A.1.5 for conditions (b) and (c)

CP.4.3 Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement

CP.4.3.1 For the avoidance of doubt, the process in this CP does not apply to Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement.

CP.5 ENERGISATION OPERATIONAL NOTIFICATION

CP.5.1 The following provisions apply in relation to the issue of an Energisation Operational Notification.
**CP.5.1.1** Certain provisions relating to the connection and energisation of the GB Code User’s Plant and Apparatus at the Connection Site and OTSUA at the Transmission Interface Point and in certain cases of Embedded Plant and Apparatus are specified in the CUSC and/or CUSC Contract(s). For other Embedded Plant and Apparatus, the Distribution Code, the DCUSA and the Embedded Development Agreement for the connection specify equivalent provisions. Further detail on this is set out in CP.5 below.

**CP.5.2** The items for submission prior to the issue of an Energisation Operational Notification are set out in CC.5.2.

**CP.5.3** In the case of a Generator or DC Converter Station owner, the items referred to in CC.5.2 shall be submitted using the User Data File Structure.

**CP.5.4** Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the GB Code User wishing to energise its Plant and Apparatus (including passive OTSUA) for the first time, the GB Code User will submit to The Company, a Certificate of Readiness to Energise High Voltage Equipment which specifies the items of Plant and Apparatus (including OTSUA) ready to be energised in a form acceptable to The Company.

**CP.5.5** If the relevant obligations under the provisions of the CUSC and/or CUSC Contract(s) and the conditions of CP.5 have been completed to The Company's reasonable satisfaction, then The Company shall issue an Energisation Operational Notification. Any dynamically controlled reactive compensation OTSUA (including Statcoms or Static Var Compensators) shall not be Energised until the appropriate Interim Operational Notification has been issued in accordance with CP.6.

**CP.6** **INTERIM OPERATIONAL NOTIFICATION**

**CP.6.1** The following provisions apply in relation to the issue of an Interim Operational Notification.

**CP.6.2** Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator or DC Converter Station owner wishing to Synchronise its Plant and Apparatus or dynamically controlled OTSUA for the first time, the Generator or DC Converter Station owner will:

(i) submit to The Company, a Notification of User’s Intention to Synchronise; and

(ii) submit to The Company the items referred to at CP.6.3.

**CP.6.3** Items for submission prior to issue of the Interim Operational Notification.

**CP.6.3.1** Prior to the issue of an Interim Operational Notification in respect of the GB Code User’s Plant and Apparatus or dynamically controlled OTSUA, the Generator or DC Converter Station owner must submit to The Company to The Company’s satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand;

(b) details of any special Power Station, Generating Unit(s), Power Park Module(s) or DC Converter Station(s) protection as applicable. This may include Pole Slipping protection and islanding protection schemes;

(c) any items required by CP.5.2, updated by the GB Code User as necessary;

(d) simulation study provisions of Appendix CP.A.3 and the results demonstrating compliance with Grid Code requirements of:

- PC.A.5.4.2
- PC.A.5.4.3.2,
CC.6.3.4,
CC.6.3.7(c)(i),
CC.6.3.15,
CC.A.6.2.5.6,
CC.A.7.2.3.1,
as applicable to the Power Station, Generating Unit(s), Power Park Module(s) or DC Converter(s) or dynamically controlled OTSUA unless agreed otherwise by The Company;

(e) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Generator or DC Converter Station owner under CP.7.2 to demonstrate compliance with relevant Grid Code requirements. Such schedule to be consistent with Appendix OC5.A.2 (in the case of Generating Units other than Power Park Modules) or Appendix OC5.A.3 (in the case of Generating Units comprising Power Park Modules) and OTSUA as applicable); and

(f) an interim Compliance Statement and a User Self Certification of Compliance completed by the GB Code User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Generator or DC Converter Station owner has identified that will not or may not be met or demonstrated.

CP.6.2 The items referred to in CP.6.3 shall be submitted by the Generator or DC Converter Station owner using the User Data File Structure.

CP.6.4 No Generating Unit, CCGT Module, Power Park Module or DC Converter or dynamically controlled OTSUA shall be Synchronised to the Total System (and for the avoidance of doubt, dynamically controlled OTSUA will not be able to transmit), until the later of:

(a) the date specified by The Company in the Interim Operational Notification issued in respect of the Generating Unit(s), CCGT Module(s), Power Park Module(s) or DC Converter(s) or dynamically controlled OTSUA; and,

(b) if Embedded, the date of receipt of a confirmation from the Network Operator in whose System the Plant and Apparatus is connected that it is acceptable to the Network Operator that the Plant and Apparatus be connected and Synchronised; and,

(c) in the case of Synchronous Generating Unit(s) only after the date of receipt by a Generator of written confirmation from The Company that the Generating Unit or CCGT Module as applicable, has completed the following tests to demonstrate compliance with the relevant provisions of the Connection Conditions to The Company’s satisfaction:

(i) those tests required to establish the open and short circuit saturation characteristics of the Generating Unit (as detailed in Appendix OC5.A.2.3) to enable assessment of the short circuit ratio in accordance with CC.6.3.2. Such tests may be carried out at a location other than the Power Station site; and

(ii) open circuit step response tests (as detailed in Appendix OC5.A.2.2) to demonstrate compliance with CC.A.6.2.4.1.

CP.6.5 The Company shall assess the schedule of tests submitted by the Generator or DC Converter Station owner with the Notification of User’s Intention to Synchronise under CP.6.1 and shall determine whether such schedule has been completed to The Company’s satisfaction.

CP.6.6 When the requirements of CP.6.2 to CP.6.5 have been met, The Company will notify the Generator or DC Converter Station owner that the:

Generating Unit,
C

Power Park Module,
Dynamically controlled OTSUA or
DC Converter,
as applicable may (subject to the Generator or DC Converter Station owner having fulfilled the requirements of CP.6.3 where that applies) be Synchronised to the Total System through the issue of an Interim Operational Notification. Where the Generator is undertaking OTSDUW, then the Interim Operational Notification will be in two parts, with the “Interim Operational Notification Part A” applicable to the OTSUA and the “Interim Operational Notification Part B” applicable to the GB Code Users Plant and Apparatus. For the avoidance of doubt, the Interim Operational Notification Part A and the Interim Operational Notification Part B can be issued together or at different times. In respect of an Embedded Power Station or Embedded DC Converter Station (other than Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement), The Company will notify the Network Operator that an Interim Operational Notification has been issued.

CP.6.6.1 The Interim Operational Notification will be time limited, the expiration date being specified at the time of issue. The Interim Operational Notification may be renewed by The Company.

CP.6.6.2 The Generator or DC Converter Station owner must operate the Generating Unit, CC

Module, Power Park Module, OTSUA or DC Converter in accordance with the terms, arising from the Unresolved Issues, of the Interim Operational Notification. Where practicable, The Company will discuss such terms with the Generator or DC Converter Station owner prior to including them in the Interim Operational Notification.

CP.6.6.3 The Interim Operational Notification will include the following limitations:

(a) In the case of OTSUA, the Interim Operational Notification Part A permits Synchronisation of the dynamically controlled OTSUA to the Total System only for the purposes of active control of voltage and Reactive Power and not for the purpose of exporting Active Power.

(b) In the case of a Power Park Module, the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) will limit the proportion of the Power Park Module which can be simultaneously Synchronised to the Total System such that neither of the following figures are exceeded:

(i) 20% of the Registered Capacity of the Power Park Module (or the output of a single Power Park Unit, where this exceeds 20% of the Power Station’s Registered Capacity); nor

(ii) 50MW

until the Generator has completed the voltage control tests (detailed in OC5.A.3.2) (including in respect of any dynamically controlled OTSUA) to The Company’s reasonable satisfaction. Following successful completion of this test, each additional Power Park Unit should be included in the voltage control scheme as soon as is technically possible (unless The Company agrees otherwise).

(b) In the case of a Power Park Module with a Registered Capacity greater or equal to 100MW, the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) will limit the proportion of the Power Park Module which can be simultaneously Synchronised to the Total System to 70% of Registered Capacity until the Generator has completed the Limited Frequency Sensitive Mode control tests with at least 50% of the Registered Capacity of the Power Park Module in service (detailed in OC5.A.3.3) to The Company’s reasonable satisfaction.
(c) In the case of a Synchronous Generating Unit, employing a static Excitation System the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) may if applicable limit the maximum Active Power output and reactive power output of the Synchronous Generating Unit or CCGT module prior to the successful commissioning of the Power System Stabiliser to The Company's satisfaction.

CP.6.6.4 When a GB Code User and The Company are acting/operating in accordance with the provisions of an Interim Operational Notification, whilst it is in force, the relevant provisions of the Grid Code to which that Interim Operational Notification relates will not apply to the GB Code User or The Company to the extent and for the period set out in the Interim Operational Notification.

CP.6.7 Other than Unresolved Issues that are subject to tests required under CP.7.2 to be witnessed by The Company, the Generator or DC Converter Station owner must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Generator or DC Converter Station owner must liaise with The Company in respect of such resolution. The tests that may be witnessed by The Company are specified in CP.7.2.

CP.6.8 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator or DC Converter Station owner wishing to commence tests required under CP.7.2 to be witnessed by The Company, the Generator or DC Converter Station owner will notify The Company that the Generating Unit(s), CCGT Module(s), Power Park Module(s) or DC Converter(s) as applicable, is ready to commence such tests.

CP.6.9 The items referred to at CP.7.3 shall be submitted by the Generator or the DC Converter Station owner after successful completion of the tests required under CP.7.2.

CP.7. FINAL OPERATIONAL NOTIFICATION

CP.7.1 The following provisions apply in relation to the issue of a Final Operational Notification.

CP.7.2 Tests to be carried out prior to issue of the Final Operational Notification

CP.7.2.1 Prior to the issue of a Final Operational Notification, the Generator or DC Converter Station owner must have completed the tests specified in this CP.7.2.2 to The Company’s satisfaction to demonstrate compliance with the relevant Grid Code provisions.

CP.7.2.2 In the case of any Generating Unit, CCGT Module, Power Park Module, OTSUA (if applicable) and DC Converter these tests will comprise one or more of the following:

(a) reactive capability tests to demonstrate that the Generating Unit, CCGT Module, Power Park Module, OTSUA (if applicable) and DC Converter can meet the requirements of CC.6.3.2. These may be witnessed by The Company on site if there is no metering to The Company Control Centre.

(b) voltage control system tests to demonstrate that the Generating Unit, CCGT Module, Power Park Module, OTSUA (if applicable) and DC Converter can meet the requirements of CC.6.3.6, CC.6.3.8 and, in the case of a Power Park Module, OTSUA (if applicable) and DC Converter, the requirements of CC.A.7 and, in the case of a Generating Unit and/or CCGT Module, the requirements of CC.A.6, and any terms specified in the Bilateral Agreement as applicable. These tests may also be used to validate the Excitation System model (PC.A.5.3) or voltage control system model (PC.A.5.4) as applicable. These tests may be witnessed by The Company.
(c) governor or frequency control system tests to demonstrate that the Generating Unit, CCGT Module, OTSUA (if applicable) and Power Park Module can meet the requirements of CC.6.3.6, CC.6.3.7, where applicable CC.A.3, and BC.3.7. The results will also validate the Mandatory Service Agreement required by CC.8.1. These tests may also be used to validate the Governor model (PC.A.5.3) or frequency control system model (PC.A.5.4) as applicable. These tests may be witnessed by The Company.

(d) fault ride through tests in respect of a Power Station with a Registered Capacity of 100MW or greater, comprised of one or more Power Park Modules, to demonstrate compliance with CC.6.3.15 (a), (b) and (c), CC.A.4.1, CC.A.4.2 and CC.A.4.3. Where test results from a Manufacturers Data & Performance Report as defined in CP.10 have been accepted this test will not be required.

(e) any further tests reasonably required by The Company, and agreed with the GB Code User to demonstrate any aspects of compliance with the Grid Code and the CUSC Contract.

CP.7.2.3 The Company’s preferred range of tests to demonstrate compliance with the CC are specified in Appendix OC5.A.2 (in the case of Generating Units other than Power Park Modules) or Appendix OC5.A.3 (in the case of Generating Units comprising Power Park Modules or OTSUA if applicable) or Appendix OC5.A.4 (in the case of DC Converters) and are to be carried out by the GB Code User with the results of each test provided to The Company. The GB Code User may carry out an alternative range of tests if this is agreed with The Company. The Company may agree a reduced set of tests where there is a relevant Manufacturers Data & Performance Report as detailed in CP.10.

CP.7.2.4 In the case of Offshore Power Park Modules which do not contribute to Offshore Transmission Licensee Reactive Power capability as described in CC.6.3.2(e)(i) or CC.6.3.2(e)(ii) or Voltage Control as described in CC.6.3.8(b)(i), the tests outlined in CP.7.2.2 (a) and CP.7.2.2 (b) are not required. However, the offshore Reactive Power transfer tests outlined in OC5.A.2.8 shall be completed in their place.

CP.7.2.5 Following completion of each of the tests specified in this CP.7.2, The Company will notify the Generator or DC Converter Station owner whether, in the opinion of The Company, the results demonstrate compliance with the relevant Grid Code conditions.

CP.7.2.6 The Generator or DC Converter Station owner is responsible for carrying out the tests and retains the responsibility for safety and personnel during the test.

CP.7.3 Items for submission prior to issue of the Final Operational Notification

CP.7.3.1 Prior to the issue of a Final Operational Notification, the Generator or DC Converter Station owner must submit to The Company to The Company’s satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with validated actual values and updated estimates for the future including Forecast Data items such as Demand;

(b) any items required by CP.5.2 and CP.6.3, updated by the GB Code User as necessary;

(c) evidence to The Company’s satisfaction that demonstrates that the controller models and/or parameters (as required under PC.A.5.3.2(c) option 2, PC.A.5.3.2(d) option 2, PC.A.5.4.2, and/or PC.A.5.4.3.2) supplied to The Company provide a reasonable representation of the behaviour of the GB Code User’s Plant and Apparatus and OTSUA if applicable;

(d) results from the tests required in accordance with CP.7.2 carried out by the Generator to demonstrate compliance with relevant Grid Code requirements including the tests witnessed by The Company; and

(e) the final Compliance Statement and a User Self Certification of Compliance signed by the GB Code User and a statement of any requirements that the Generator or DC Converter Station owner has identified that have not been met together with a copy of the derogation in respect of the same from the Authority.
CP.7.3.2 The items in CP.7.3 should be submitted by the Generator (including in respect of any OTSUA if applicable) or DC Converter Station owner using the User Data File Structure.

CP.7.4 If the requirements of CP.7.2 and CP.7.3 have been successfully met, The Company will notify the Generator or DC Converter Station owner that compliance with the relevant Grid Code provisions has been demonstrated for the Generating Unit(s), CCGT Module(s), Power Park Module(s), OTSUA, if applicable or DC Converter(s) as applicable through the issue of a Final Operational Notification. In respect of an Embedded Power Station or Embedded DC Converter Station other than Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement, The Company will notify the Network Operator that a Final Operational Notification has been issued.

CP.7.5 If a Final Operational Notification cannot be issued because the requirements of CP.7.2 and CP.7.3 have not been successfully met prior to the expiry of an Interim Operational Notification, then the Generator or DC Converter Station owner (where licensed in respect of its activities) and/or The Company, shall apply to the Authority for a derogation. The provisions of CP.9 shall then apply.

CP.8 LIMITED OPERATIONAL NOTIFICATION

CP.8.1 Following the issue of a Final Operational Notification if:

(i) the Generator or DC Converter Station owner becomes aware, that the capability of its Plant and/or Apparatus (including OTSUA if applicable) to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement is not fully available, then the Generator or DC Converter Station owner shall follow the process in CP.8.2 to CP.8.11; or,

(ii) a Network Operator becomes aware, that the capability of Plant and/or Apparatus belonging to an Embedded Power Station or Embedded DC Converter Station (other than Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement) is failing to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement, then the Network Operator shall inform The Company and The Company shall inform the Generator or DC Converter Station owner to then follow the process in CP.8.2 to CP.8.11; or,

(iii) The Company becomes aware through monitoring as described in OC5.4, that a Generator or DC Converter Station owner Plant and/or Apparatus (including OTSUA if applicable) capability to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement is not fully available, then The Company shall inform the other party. Where The Company and the Generator or DC Converter Station owner cannot agree from the monitoring as described in OC5.4 whether the Plant and/or Apparatus (including OTSUA if applicable) is fully available and/or is compliant with the requirements of the Grid Code and where applicable the Bilateral Agreement, the parties shall first apply the process in OC5.5.1, before applying the process defined in CP.8 (LON) if applicable. Where the testing instructed in accordance with OC.5.5.1 indicates that the Plant and/or Apparatus (including OTSUA if applicable) is not fully available and/or is not compliant with the requirements of the Grid Code and/or the Bilateral Agreement, or if the parties so agree, the process in CP.8.2 to CP.8.11 shall be followed.

CP.8.2 Immediately upon a Generator or DC Converter Station owner becoming aware that its Generating Unit, CCGT Module, Power Park Module, OTSUA (if applicable) or DC Converter Station as applicable may be unable to comply with certain provisions of the Grid Code or (where applicable) the Bilateral Agreement, the Generator or DC Converter Station owner shall notify The Company in writing. Additional details of any operating restrictions or changes in applicable data arising from the potential non-compliance and an indication of the date from when the restrictions will be removed and full compliance demonstrated shall be provided as soon as reasonably practical.
CP.8.3 If the nature of any unavailability and/or potential non-compliance described in CP.8.1 causes or can reasonably be expected to cause a material adverse effect on the business or condition of The Company or other Users or the National Electricity Transmission System or any User Systems, then The Company may, notwithstanding the provisions of this CP.8, follow the provisions of Paragraph 5.4 of the CUSC.

CP.8.4 Except where the provisions of CP.8.3 apply, where the restriction notified in CP.8.2 is not resolved in 28 days, then the Generator or DC Converter Station owner with input from and discussion of conclusions with The Company, and the Network Operator where the Generating Unit, CCGT Module, Power Park Module or Power Station as applicable is Embedded, shall undertake an investigation to attempt to determine the causes of and solution to the non-compliance. Such investigation shall continue for no longer than 56 days. During such investigation, the Generator or DC Converter Station owner shall provide to The Company, the relevant data which has changed due to the restriction in respect of CP.7.3.1 as notified to the Generator or DC Converter Station owner by The Company as being required to be provided.

CP.8.5 Issue and Effect of LON

CP.8.5.1 Following the issue of a Final Operational Notification, The Company will issue to the Generator or DC Converter Station owner, a Limited Operational Notification if:

(a) by the end of the 56 day period referred to at CP.8.4, the investigation has not resolved the non-compliance to The Company’s satisfaction; or

(b) The Company is notified by a Generator or DC Converter Station owner of a Modification to its Plant and Apparatus (including OTSUA if applicable); or

(c) The Company receives a submission of data, or a statement from a Generator or DC Converter Station owner indicating a change in Plant or Apparatus (including OTSUA if applicable) or settings (including but not limited to governor and excitation control systems) that may in The Company’s reasonable opinion, acting in accordance with Good Industry Practice be expected to result in a material change of performance.

In the case of an Embedded Generator or Embedded DC Converter Station owner, The Company will issue a copy of the Limited Operational Notification to the Network Operator.

CP.8.5.2 The Limited Operational Notification will be time limited to expire no later than 12 months from the start of the non-compliance or restriction or from reconnection following a change. The Company may agree a longer duration in the case of a Limited Operational Notification following a Modification or whilst the Authority is considering the application for a derogation in accordance with CP.9.1.

CP.8.5.3 The Limited Operational Notification will notify the Generator or DC Converter Station owner of any restrictions on the operation of the Generating Unit(s), CCGT Module(s), Power Park Module(s), OTSUA (if applicable) or DC Converter(s) and will specify the Unresolved Issues. The Generator or DC Converter Station owner must operate in accordance with any notified restrictions and must resolve the Unresolved Issues.

CP.8.5.4 When a GB Code User and The Company are acting/operating in accordance with the provisions of a Limited Operational Notification, whilst it is in force, the relevant provisions of the Grid Code to which that Limited Operational Notification relates will not apply to the GB Code User or The Company to the extent and for the period set out in the Limited Operational Notification.

CP.8.5.5 The Unresolved Issues included in a Limited Operational Notification will show the extent that the provisions of CP.7.2 (testing) and CP.7.3 (final data submission) shall apply. In respect of selecting the extent of any tests which may in The Company’s view reasonably be needed to demonstrate the restored capability and in agreeing the time period in which the tests will be scheduled, The Company shall, where reasonably practicable, take account of the Generator or DC Converter Station owner’s input to contain its costs associated with the testing.
In the case of a change or Modification the Limited Operational Notification may specify that the affected Plant and/or Apparatus (including OTSUA if applicable) or associated Generating Unit(s) or Power Park Unit(s) must not be Synchronised until all of the following items, that in The Company's reasonable opinion are relevant, have been submitted to The Company to The Company's satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data);

(b) details of any relevant special Power Station, Generating Unit(s), Power Park Module(s), OTSUA (if applicable) or DC Converter Station(s) protection as applicable. This may include Pole Slipping protection and islanding protection schemes; and

(c) simulation study provisions of Appendix CP.A.3 and the results demonstrating compliance with Grid Code requirements relevant to the change or Modification as agreed by The Company; and

(d) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Generator or DC Converter Station to demonstrate compliance with relevant Grid Code requirements as agreed by The Company. The schedule of tests shall be consistent with Appendix OC5.A.2 or Appendix OC5.A.3 as appropriate; and

(e) an interim Compliance Statement and a User Self Certification of Compliance completed by the GB Code User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Generator or DC Converter Station owner has identified that will not or may not be met or demonstrated; and

(f) any other items specified in the LON.

CP.8.5.7 The items referred to in CP.8.5.6 shall be submitted by the Generator (including in respect of any OTSUA if applicable) or DC Converter Station owner using the User Data File Structure.

CP.8.5.8 In the case of Synchronous Generating Unit(s) only, the Unresolved Issues of the LON may require that the Generator must complete the following tests to The Company's satisfaction to demonstrate compliance with the relevant provisions of the CCs prior to the Generating Unit being Synchronised to the Total System:

(a) those tests required to establish the open and short circuit saturation characteristics of the Generating Unit (as detailed in Appendix OC5.A.2.3) to enable assessment of the short circuit ratio in accordance with CC.6.3.2. Such tests may be carried out at a location other than the Power Station site; and

(b) open circuit step response tests (as detailed in Appendix OC5.A.2.2) to demonstrate compliance with CC.A.6.2.4.1.

CP.8.6 In the case of a change or Modification, not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion, prior to the Generator or DC Converter Station owner wishing to Synchronise its Plant and Apparatus (including OTSUA if applicable) for the first time following the change or Modification, the Generator or DC Converter Station owner will:

(i) submit a Notification of User's Intention to Synchronise; and

(ii) submit to The Company the items referred to at CP.8.5.6.

CP.8.7 Other than Unresolved Issues that are subject to tests to be witnessed by The Company, the Generator or DC Converter Station owner must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Generator or DC Converter Station owner must liaise with The Company in respect of such resolution. The tests that may be witnessed by The Company are specified in CP.7.2.2.
CP.8.8 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator or DC Converter Station owner wishing to commence tests listed as Unresolved Issues to be witnessed by The Company, the Generator or DC Converter Station owner will notify The Company that the Generating Unit(s), CCGT Module(s), Power Park Module(s), OTSUA (if applicable) or DC Converter(s) as applicable is ready to commence such tests.

CP.8.9 The items referred to at CP.7.3 and listed as Unresolved Issues shall be submitted by the Generator or the DC Converter Station owner after successful completion of the tests.

CP.8.10 Where the Unresolved Issues have been resolved, a Final Operational Notification will be issued to the GB Code User.

CP.8.11 If a Final Operational Notification has not been issued by The Company within the 12 month period referred to at CP.8.5.2 (or where agreed following a Modification by the expiry time of the LON) then the Generator or DC Converter Station owner (where licensed in respect of its activities) and The Company shall apply to the Authority for a derogation.

CP.9 PROCESSES RELATING TO DEROGATIONS

CP.9.1 Whilst the Authority is considering the application for a derogation, the Interim Operational Notification or Limited Operational Notification will be extended to remain in force until the Authority has notified The Company and the Generator or DC Converter Station owner of its decision. Where the Generator or DC Converter Station owner is not licensed, The Company may propose any necessary changes to the Bilateral Agreement with such unlicensed Generator or DC Converter Station owner.

CP.9.2 If the Authority:

(a) grants a derogation in respect of the Plant and/or Apparatus, then The Company shall issue a Final Operational Notification once all other Unresolved Issues are resolved; or

(b) decides a derogation is not required in respect of the Plant and/or Apparatus, then The Company will reconsider the relevant Unresolved Issues and may issue a Final Operational Notification once all other Unresolved Issues are resolved; or

(c) decides not to grant any derogation in respect of the Plant and/or Apparatus, then there will be no Operational Notification in place and The Company and the GB Code User shall consider its rights pursuant to the CUSC.

CP.9.3 Where an Interim Operational Notification or Limited Operational Notification is so conditional upon a derogation and such derogation includes any conditions (including any time limit to such derogation), the Generator or DC Converter Station owner will progress the resolution of any Unresolved Issues and / or progress and / or comply with any conditions upon such derogation and the provisions of CP.6.9 to CP.7.4 shall apply and shall be followed.

CP.10 MANUFACTURER’S DATA & PERFORMANCE REPORT

CP.10.1.1 Data and performance characteristics in respect of certain Grid Code requirements may be registered with The Company by Power Park Unit manufacturers in respect of specific models of Power Park Units by submitting information in the form of a Manufacturer’s Data and Performance Report to The Company.
A GB Generator planning to construct a Power Station containing the appropriate version of Power Park Units in respect of which a Manufacturer’s Data & Performance Report has been submitted to The Company may reference the Manufacturer’s Data & Performance Report in its submissions to The Company. Any Generator considering referring to a Manufacturer’s Data & Performance Report for any aspect of its Plant and Apparatus may contact The Company to discuss the suitability of the relevant Manufacturer’s Data & Performance Report to its project to determine if, and to what extent, the data included in the Manufacturer’s Data & Performance Report contributes towards demonstrating compliance with those aspects of the Grid Code applicable to the Generator. The Company will inform the Generator if the reference to the Manufacturer’s Data & Performance Report is not appropriate or not sufficient for its project.

The process to be followed by Power Park Unit manufacturers submitting a Manufacturer’s Data & Performance Report is agreed by The Company. CP.10.2 indicates the specific Grid Code requirement areas in respect of which a Manufacturer’s Data & Performance Report may be submitted.

The Company will maintain and publish a register of those Manufacturer’s Data & Performance Reports which The Company has received and accepted as being an accurate representation of the performance of the relevant Plant and / or Apparatus. Such register will identify the manufacturer, the model(s) of Power Park Unit(s) to which the report applies and the provisions of the Grid Code in respect of which the report contributes towards the demonstration of compliance. The inclusion of any report in the register does not in any way confirm that any Power Park Modules which utilise any Power Park Unit(s) covered by a report is or will be compliant with the Grid Code.

A Manufacturer’s Data & Performance Report in respect of Power Park Units may cover one (or part of one) or more of the following provisions of the Grid Code:

(a) Fault Ride Through capability CC.6.3.15
(b) Power Park Module mathematical model PC.A.5.4.2

Reference to a Manufacturer’s Data & Performance Report in a GB Code User’s submissions does not by itself constitute compliance with the Grid Code.

A Generator referencing a Manufacturer’s Data & Performance Report should insert the relevant Manufacturer’s Data & Performance Report reference in the appropriate place in the DRC data submission and / or in the User Data File Structure. The Company will consider the suitability of a Manufacturer’s Data & Performance Report:

(a) in place of DRC data submissions, a mathematical model suitable for representation of the entire Power Park Module as per CP.A.3.4.4. For the avoidance of doubt only the relevant sections as specified in PC.A.2.5.5.7 apply. Site specific parameters will still need to be submitted by the Generator.

(b) in place of fault simulation studies as follows;

The Company will not require Fault Ride Through simulation studies to be conducted as per CP.A.3.5.2 provided that;

(i) Adequate and relevant Power Park Unit data is included in respect of Fault Ride Through testing covered in CP.A.14.7.1 in the relevant Manufacturer’s Data & Performance Report, and

(ii) For each type and duration of fault as detailed in CP.A.3.5.1, the expected minimum retained voltage is greater than the corresponding minimum voltage achieved and successfully ridden through in the fault ride through tests covered by the Manufacturer’s Data & Performance Report.

(c) to reduce the scope of compliance site tests as follows;

(i) Where there is a Manufacturer’s Data & Performance Report in respect of a Power Park Unit which covers Fault Ride Through, The Company may agree that no Fault Ride Through testing is required.
CP.10.5  It is the responsibility of the **GB Code User** to ensure that the correct reference for the **Manufacturer’s Data & Performance Report** is used and the **GB Code User** by using that reference accepts responsibility for the accuracy of the information. The **GB Code User** shall ensure that the manufacturer has kept **The Company** informed of any relevant variations in plant specification since the submission of the relevant **Manufacturer’s Data & Performance Report** which could impact on the validity of the information.

CP.10.6  **The Company** may contact the **Power Park Unit** manufacturer directly to verify the relevance of the use of such **Manufacturer’s Data & Performance Report**. If **The Company** believe the use some or all of such **Manufacturer’s Data & Performance Report** information is incorrect or the referenced data is inappropriate then the reference to the **Manufacturer’s Data & Performance Report** may be declared invalid by **The Company**. Where, and to the extent possible, the data included in the **Manufacturer’s Data & Performance Report** is appropriate, the compliance assessment process will be continued using the data included in the **Manufacturer’s Data & Performance Report**.
APPENDIX 1 - ILLUSTRATIVE PROCESS DIAGRAMS

CP.A.1.1 Illustrative Compliance Process for Energisation of a User

User Activities

- Acceptance of CUSC Contract
- Submission of Data PC.4.4.2
- Submission of Information (CP.5.2) in User Data File Structure (CP.5.3)
- Submit Certificate of Readiness to Energise High Voltage Equipment (CP.5.4)
- Energise User System

The Company Activities

- Start of Connection Process
- Review for completeness
- Initiate ongoing progress meetings with review of information submissions
- Review of information submission
- Issue Energisation Operational Notification (CP.5.5)

The process illustrated in CP.A.1.1 applies to all GB Code Users energising passive network Plant and Apparatus including Distribution Network Operators, Non-Embedded Customers, Generators and DC Converter Station owners. This process is a subset of the full process for Generators and DC Converter Station owners shown in CP.A.1.2. This diagram illustrates the process in the CP and includes references in brackets to specific Grid Code clauses.
This diagram illustrates the process in the CP and includes references in brackets to specific Grid Code clauses. For the avoidance of doubt this process does not apply to Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded DC Converter Stations not subject to a Bilateral Agreement.
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APPENDIX 2 - USER SELF CERTIFICATION OF COMPLIANCE

USER SELF CERTIFICATION OF COMPLIANCE (Interim/Final)

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<tr>
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<td>[Full User name]</td>
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<tr>
<td>Registered Capacity (MW) of Plant:</td>
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This User Self Certification of Compliance records the compliance by the GB Code User in respect of [NAME] Power Station/DC Converter Station [and, in the case of OTSDUW Arrangements, OTSUA] with the Grid Code and the requirements of the Bilateral Agreement and Construction Agreement dated [   ] with reference number [   ]. It is completed by the Power Station/DC Converter Station owner in the case of Plant and/or Apparatus (including OTSUA) connected to the National Electricity Transmission System and for Embedded Plant.

We have recorded our compliance against each requirement of the Grid Code which applies to the Power Station/DC Converter Station/OTSUA, together with references to supporting evidence and a commentary where this is appropriate, and have provided this to The Company. A copy of the Compliance Statement is attached.

Supporting evidence, in the form of simulation results, test results, manufacturer’s data and other documentation, is attached in the User Data File Structure.

The GB Code User hereby certifies that, to the best of its knowledge and acting in accordance with Good Industry Practice, [the Power Station is compliant with the Grid Code and the Bilateral Agreement] [the OTSUA is compliant with the Grid Code and the Construction Agreement] in all aspects [with the following Unresolved Issues*] [with the following derogation(s)**]:

<table>
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** Compliance certified by:**

Name: [PERSON]  
Signature: [PERSON]  
Date:  

Title: [PERSON DESIGNATION]  
Of  
[GB CODE USER DETAILS]

* Include for Interim User Self Certification of Compliance ahead of Interim Operational Notification.

** Include for final User Self Certification of Compliance ahead of Final Operational Notification where derogation(s) have been granted. If no derogation(s) required delete wording and Table.
APPENDIX 3 - SIMULATION STUDIES

CP.A.3.1.1 This Appendix sets out the simulation studies required to be submitted to The Company to demonstrate compliance with the Connection Conditions unless otherwise agreed with The Company. This Appendix should be read in conjunction with CP.6 with regard to the submission of the reports to The Company. Where there is any inconsistency in the technical requirements in respect of which compliance is being demonstrated by simulation in this Appendix and CC.6.3 and the Bilateral Agreement, the provisions of the Bilateral Agreement and CC.6.3 prevail. The studies specified in this Appendix will normally be sufficient to demonstrate compliance. However The Company may agree an alternative set of studies proposed by the Generator or DC Converter Station owner provided The Company deem the alternative set of studies sufficient to demonstrate compliance with the Grid Code and the Bilateral Agreement.

CP.A.3.1.2 The Generator or DC Converter Station owner shall submit simulation studies in the form of a report to demonstrate compliance. In all cases, the simulation studies must utilise models applicable to the Generating Unit, DC Converter or Power Park Module with proposed or actual parameter settings. Reports should be submitted in English with all diagrams and graphs plotted clearly with legible axes and scaling provided to ensure any variations in plotted values is clear.

CP.A.3.1.3 In the case of an Offshore Power Station where OTSDUW Arrangements apply, simulation studies by the Generator should include the action of any relevant OTSUA where applicable to demonstrate compliance with the Grid Code and the Bilateral Agreement at the Interface Point.

CP.A.3.2 Power System Stabiliser Tuning

CP.A.3.2.1 In the case of a Synchronous Generating Unit, the Power System Stabiliser tuning simulation study report required by CC.A.6.2.5.6 or required by the Bilateral Agreement shall contain:

(i) the Excitation System model including the Power System Stabiliser with settings as required under the Planning Code (PC.A.5.3.2(c)).

(ii) open circuit time series simulation study of the response of the Excitation System to a +10% step change from 90% to 100% terminal voltage.

(iii) on load time series dynamic simulation studies of the response of the Excitation System with and without the Power System Stabiliser to 2% and 10% steps in the reference voltage and a three phase short circuit fault applied to the higher voltage side of the Generating Unit transformer for 100ms. The simulation studies should be carried out with the Generating Unit operating at full Active Power and maximum leading Reactive Power import with the fault level at the Supergrid HV Connection Point at minimum or as otherwise agreed with The Company. The results should show Generating Unit field voltage, Generating Unit terminal voltage, Power System Stabiliser output, Generating Unit Active Power and Generating Unit Reactive Power output.

(iv) gain and phase Bode diagrams for the open loop frequency domain response of the Generating Unit Excitation System with and without the Power System Stabiliser. These should be in a suitable format to allow assessment of the phase contribution of the Power System Stabiliser and the gain and phase margin of the Excitation System with and without the Power System Stabiliser in service.

(v) an eigenvalue plot to demonstrate that all modes remain stable when the Power System Stabiliser gain is increased by at least a factor of 3 from the designed operating value.
(vi) gain Bode diagram for the closed loop on load frequency domain response of the Generating Unit Excitation System with and without the Power System Stabiliser with the Generating Unit operating at full load and at unity Power Factor. These diagrams should be in a suitable format to allow comparison of the Active Power damping across the frequency range specified in CC.A.6.2.6.3 with and without the Power System Stabiliser in service.

In the case of a Synchronous Generating Unit that may operate as demand (eg. Pump Storage) the on load simulations (ii) to (vi) should also be carried out in both modes of operation.

CP.A.3.2.2 In the case of Onshore Non-Synchronous Generating Units, Onshore DC Converters and Onshore Power Park Modules and OTSDUW Plant and Apparatus at the Interface Point the Power System Stabiliser tuning simulation study report required by CC.A.7.2.4.1 or required by the Bilateral Agreement shall contain:

(i) the Voltage Control System model including the Power System Stabiliser with settings as required under the Planning Code (PC.A.5.4) and Bilateral Agreement.

(ii) on load time series dynamic simulation studies of the response of the Voltage Control System with and without the Power System Stabiliser to 2% and 10% steps in the reference voltage and a three phase short circuit fault applied to the Grid Entry Point or the Interface Point in the case of OTSDUW Plant and Apparatus for 100ms. The simulation studies should be carried out operating at full Active Power and maximum leading Reactive Power (import condition) with the fault level at the Supergrid HV Connection Point at minimum or as otherwise agreed with The Company. The results should show appropriate signals to demonstrate the expected damping performance of the Power System Stabiliser.

(iii) any other simulation as specified in the Bilateral Agreement or agreed between the Generator or DC Converter Owner or Offshore Transmission Licensee and The Company.

CP.A.3.3 Reactive Capability across the Voltage Range

CP.A.3.3.1 The Generator or DC Converter station owner shall supply simulation studies to demonstrate the capability to meet CC.6.3.4 by submission of a report containing:

(i) a load flow simulation study result to demonstrate the maximum lagging Reactive Power capability of the Synchronous Generating Unit, DC Converter, OTSUA or Power Park Module at Rated MW when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in case of OTSUA) voltage is at 105% of nominal.

(ii) a load flow simulation study result to demonstrate the maximum leading Reactive Power capability of the Synchronous Generating Unit, DC Converter, OTSUA or Power Park Module at Rated MW when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in case of OTSUA) voltage is at 95% of nominal.

CP.A.3.3.2 In the case of a Synchronous Generating Unit the terminal voltage in the simulation should be the nominal voltage for the machine. Where necessary to demonstrate compliance with CC.6.3.4 and subject to compliance with CC.6.3.8 (a) (v), the Generator shall repeat the two simulation studies with the terminal voltage being greater than the nominal voltage and less than or equal to the maximum terminal voltage. The two additional simulations do not need to have the same terminal voltage.

CP.A.3.3.3 In the case of a Synchronous Generating Unit, the Generator shall supply two sets of simulation studies to demonstrate the capability to meet the operational requirements of BC2.A.2.6 and CC.6.1.7 at the minimum and maximum short circuit levels when changing tap position. Each set of simulation studies shall be at the same System conditions. None of the simulation studies shall include the Synchronous Generating Unit operating at the limits of its Reactive Power output.
The simulation results shall include the Reactive Power output of the Synchronous Generating Unit and the voltage at the Grid Entry Point or, if Embedded, the User System Entry Point with the Generating Unit transformer at two adjacent tap positions with the greatest interval between them and the terminal voltage of the Synchronous Generating Unit equal to
- its nominal value; and
- subject to compliance with CC.6.3.8 (a) (v), its maximum value.

CP.A.3.3.4 In the case of a Power Park Module where the load flow simulation studies show that the individual Power Park Units deviate from nominal voltage to meet the Reactive Power requirements, then evidence must be provided from factory (e.g. in a Manufacturer's Data & Performance Report) or site testing that the Power Park Unit is capable of operating continuously at the operating points determined in the load flow simulation studies.

CP.A.3.4 Voltage Control and Reactive Power Stability

CP.A.3.4.1 In the case of a Power Station containing Power Park Modules and/or OTSUA the Generator shall provide a report to demonstrate the dynamic capability and control stability of the Power Park Module. The report shall contain:

(i) a dynamic time series simulation study result of a sufficiently large negative step in System voltage to cause a change in Reactive Power from zero to the maximum lagging value at Rated MW.

(ii) a dynamic time series simulation study result of a sufficiently large positive step in System voltage to cause a change in Reactive Power from zero to the maximum leading value at Rated MW.

(iii) a dynamic time series simulation study result to demonstrate control stability at the lagging Reactive Power limit by application of a -2% voltage step while operating within 5% of the lagging Reactive Power limit.

(iv) a dynamic time series simulation study result to demonstrate control stability at the leading Reactive Power limit by application of a +2% voltage step while operating within 5% of the leading Reactive Power limit.

(v) a dynamic time series simulation study result of a sufficiently negative step in System voltage to cause a change in Reactive Power from the maximum leading value to the maximum lagging value at Rated MW.

The Generator should also provide the voltage control study specified in CP.A.3.7.4.

CP.A.3.4.2 All the above studies should be completed with a nominal network voltage for zero Reactive Power transfer at the Grid Entry Point or User System Entry Point if Embedded or, in the case of OTSUA, Interface Point unless stated otherwise and the fault level at the HV connection point at minimum as agreed with The Company.

CP.A.3.4.3 The Company may permit relaxation from the requirements of CP.A.3.4.1(i) and (ii) for voltage control if the Power Park Modules are comprised of Power Park Units in respect of which the GB Code User has in its submissions to The Company, referenced an appropriate Manufacturer's Data & Performance Report which is acceptable to The Company for voltage control.

CP.A.3.4.4 In addition, The Company may permit a further relaxation from the requirements of CP.A.3.4.1(iii) and (iv) if the GB Code User has in its submissions to The Company referenced an appropriate Manufacturer's Data & Performance Report for a Power Park Module mathematical model for voltage control acceptable to The Company.

CP.A.3.5 Fault Ride Through

CP.A.3.5.1 The Generator, (including where undertaking OTSDUW) or DC Converter Station owner shall supply time series simulation study results to demonstrate the capability of Non-Synchronous Generating Units, DC Converters, Power Park Modules and OTSUA to meet CC.6.3.15 by submission of a report containing:
(i) a time series simulation study of a 140ms solid three phase short circuit fault applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA.

(ii) time series simulation study of 140ms unbalanced short circuit faults applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA. The unbalanced faults to be simulated are:

1. a phase to phase fault
2. a two phase to earth fault
3. a single phase to earth fault.

For a Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA, the simulation study should be completed with the Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA operating at full Active Power and maximum leading Reactive Power import and the fault level at the Supergrid HV Connection Point at minimum or as otherwise agreed with The Company.

(iii) time series simulation studies of balanced Supergrid voltage dips applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA. The simulation studies should include:

1. 30% retained voltage lasting 0.384 seconds
2. 50% retained voltage lasting 0.71 seconds
3. 80% retained voltage lasting 2.5 seconds
4. 85% retained voltage lasting 180 seconds.

For a Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA, the simulation study should be completed with the Non-Synchronous Generating Unit, DC Converter, Power Park Module or OTSUA operating at full Active Power and zero Reactive Power output and the fault level at the Supergrid HV Connection Point at minimum or as otherwise agreed with The Company. Where the Non-Synchronous Generating Unit, DC Converter or Power Park Module is Embedded the minimum Network Operator’s System impedance to the Supergrid HV Connection Point shall be used which may be calculated from the maximum fault level at the User System Entry Point.

For DC Converters the simulations should include the duration of each voltage dip 1 to 4 above for which the DC Converter will remain connected.

CP.A.3.5.2 In the case of Power Park Modules comprised of Power Park Units in respect of which the GB Code User’s reference to a Manufacturer’s Data & Performance Report has been accepted by The Company for Fault Ride Through, CP.A.3.5.1 will not apply provided:

(i) the Generator or DC Converter Station owner demonstrates by load flow simulation study result that the faults and voltage dips at either side of the Power Park Unit transformer corresponding to the required faults and voltage dips in CP.A.3.5.1 applied at the nearest point of the National Electricity Transmission System operating at Supergrid voltage are less than those included in the Manufacturer’s Data & Performance Report,

or;

(ii) the same or greater percentage faults and voltage dips in CP.A.3.5.1 have been applied at either side of the Power Park Unit transformer in the Manufacturer’s Data & Performance Report.
In the case of an **Offshore Power Park Module** or **Offshore DC Converter**, the studies may instead be completed at the **LV Side of the Offshore Platform**. For fault simulation studies described in CCA.8.5.1(i) and CCA.8.5.1(ii) a retained voltage of 15% or lower may be applied at the **LV Side of the Offshore Platform** on the faulted phases. For voltage dip simulation studies described in CP.A.3.5.1(iii) the same voltage levels and durations as normally applied at the **National Electricity Transmission System** operating at **Supergrid Voltage** will be applied at the **LV Side of the Offshore Platform**.

**Load Rejection**

**CP.A.3.6.1** In respect of **Generating Units** or **DC Converters** or **Power Park Modules** with a **Completion Date** on or after 1 January 2012, the **Generator** or **DC Converter Station** owner shall demonstrate the speed control performance of the plant under a part load rejection condition as required by CC.6.3.7(c)(i), through simulation study. In respect of **Generating Units** or **DC Converters** or **Power Park Modules**, including those with a **Completion Date** before 1 January 2013, the load rejection capability while still supplying load must be stated in accordance with PC.A.5.3.2(f).

**CP.A.3.6.2** For **Power Park Modules** comprised of **Power Park Units** having a corresponding generically verified and validated model included in the **Manufacturer’s Data & Performance Report**, this study may not be required by The Company if the correct **Manufacturer’s Data & Performance Report** reference has been submitted in the appropriate location in the **Data Registration Code**.

**CP.A.3.6.3** The simulation study should comprise of a **Generating Unit**, **DC Converter** or **Power Park Module** connected to the total **System** with a local load shown as “X” in figure CP.A.3.6.1. The load “X” is in addition to any auxiliary load of the **Power Station** connected directly to the **Generating Unit**, **DC Converter** or **Power Park Module** and represents a small portion of the **System** to which the **Generating Unit**, **DC Converter** or **Power Park Module** is attached. The value of “X” should be the minimum for which the **Generating Unit**, **DC Converter** or **Power Park Module** can control the power island **Frequency** to less than 52Hz. Where transient excursions above 52Hz occur the **Generator** or **DC Converter Owner** should ensure that the duration above 52Hz is less than any high frequency protection system applied to the **Generating Unit**, **DC Converter** or **Power Park Module**.

**CP.A.3.6.4** At the start of the simulation study the **Generating Unit**, **DC Converter** or **Power Park Module** will be operating maximum **Active Power** output. The **Generating Unit**, **DC Converter** or **Power Park Module** will then be islanded from the **Total System** but still supplying load “X” by the opening of a breaker, which is not the **Generating Unit**, **DC Converter** or **Power Park Module** connection circuit breaker (the governor should therefore, not receive any signals that the breaker has opened other than the reduction in load and subsequent increase in speed). A schematic arrangement of the simulation study is illustrated by Figure CP.A.3.6.1.
The simulation study shall be performed for both control modes, Frequency Sensitive Mode (FSM) and Limited Frequency Sensitive Mode (LFSM). The simulation study results should indicate Active Power and Frequency in the island system that includes the Generating Unit, DC Converter or Power Park Module.

To allow validation of the model used to simulate load rejection in accordance with CC.6.3.7(c)(i) as described, a further simulation study is required to represent the largest positive Frequency injection step or fast ramp (BC1 and BC3 of Figure 2) that will be applied as a test as described in OC5.A.2.8 and OC5.A.3.6.

Voltage and Frequency Controller Model Verification and Validation

For Generating Units, DC Converters or Power Park Modules with a Completion Date after 1 January 2012 or subject to a Modification to a Excitation System, voltage control system, governor control system or Frequency control system after 1 January 2012 the Generator or DC Converter Station owner shall provide simulation studies to verify that the proposed controller models supplied to The Company under the Planning Code are fit for purpose. These simulation study results shall be provided in the timescales stated in the Planning Code. For Power Park Modules comprised of Power Park Units having a corresponding generically verified and validated model in a Manufacturer’s Data & Performance Report, The Company may permit the simulation studies detailed in CP.A.3.7.2, CP.A.3.7.4 and CP.A.3.7.5 to be replaced by submission of the correct Manufacturer’s Data & Performance Report reference in the appropriate location in the Data Registration Code.

To demonstrate the Frequency control or governor/load controller/plant model, the Generator or DC Converter Station owner shall submit a simulation study representing the response of the Synchronous Generating Unit, DC Converter or Power Park Module operating at 80% of Registered Capacity. The simulation study event shall be equivalent to:

(i) a ramped reduction in the measured System Frequency of 0.5Hz in 10 seconds followed by

(ii) 20 seconds of steady state with the measured System Frequency depressed by 0.5Hz followed by
(iii) a ramped increase in measured **System Frequency** of 0.3Hz over 30 seconds followed by

(iv) 60 seconds of steady state with the measured **System Frequency** depressed by 0.2Hz as illustrated in Figure CP.A.3.7.2 below.

![Figure CP.A.3.7.2](image)

The simulation study shall show **Active Power** output (MW) and the equivalent of **Frequency** injected.

**CP.A.3.7.3**
To demonstrate the **Excitation System** model the **Generator** shall submit simulation studies representing the response of the **Synchronous Generating Unit** as follows:

(i) operating open circuit at rated terminal voltage and subjected to a 2% step increase in terminal voltage reference.

(ii) operating at **Rated MW**, nominal terminal voltage and unity **Power Factor** subjected to a 2% step increase in the voltage reference. Where a **Power System Stabiliser** is included within the **Excitation System** this shall be in service.

The simulation study shall show the terminal voltage, field voltage of the **Generating Unit**, **Active Power**, **Reactive Power** and **Power System Stabiliser** output signal as appropriate.

**CP.A.3.7.4**
To demonstrate the **Voltage Controller** model, the **Generator** or **DC Converter Station** owner shall submit a simulation study representing the response of the **Non-Synchronous Generating Unit**, **DC Converter** or **Power Park Module** operating at **Rated MW** and unity **Power Factor** at the connection point to a 2% step increase in the voltage reference. The simulation study shall show the terminal voltage, **Active Power**, **Reactive Power** and **Power System Stabiliser** output signal as appropriate.

**CP.A.3.7.5**
To validate that the excitation and voltage control models submitted under the **Planning Code** are a reasonable representation of the dynamic behaviour of the **Synchronous Generating Unit**, **DC Converter Station** or **Power Park Module** as built, the **Generator** or **DC Converter Station** owner shall repeat the simulation studies outlined above but using the operating conditions of the equivalent tests. The simulation study results shall be displayed overlaid on the actual test results.

**CP.A.3.7.6**
For **Generating Units** or **DC Converters** with a **Completion Date** after 1 January 2012 or subject to a **Modification** to the governor system or **Frequency** control system after 1 January 2013 to validate that the governor/load controller/plant or **Frequency** control models submitted under the **Planning Code** is a reasonable representation of the dynamic behaviour of the **Synchronous Generating Unit** or **DC Converter Station** as built, the **Generator** or **DC Converter Station** owner shall repeat the simulation studies outlined above but using the operating conditions of the equivalent tests. The simulation study results shall be displayed overlaid on the actual test results.
CP.A.3.8  **Sub-synchronous Resonance Control and Power Oscillation Damping Control for DC Converters**

CP.A.3.8.1  To demonstrate the compliance of the sub-synchronous control function with CC.6.3.16(a) and the terms of the **Bilateral Agreement**, the **DC Converter Station** owner or **Generator** undertaking **OTSDUW** shall submit a simulation study report.

CP.A.3.8.2  Where power oscillation damping control function is specified on a **DC Converter** the **DC Converter Station** owner or **Generator** undertaking **OTSDUW** shall submit a simulation study report to demonstrate the compliance with CC.6.3.16(b) and the terms of the **Bilateral Agreement**.

CP.A.3.8.3  The simulation studies should utilise the **DC Converter** control system models including the settings as required under the **Planning Code** (PC.A.5.3.2). The network conditions for the above simulation studies should be discussed with **The Company** prior to commencing any simulation studies.

< END OF COMPLIANCE PROCESSES >
# EUROPEAN COMPLIANCE PROCESSES (ECP)

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EUROPEAN COMPLIANCE PROCESSES

ECP.1 INTRODUCTION

ECP.1.1 The European Compliance Processes ("ECP") specify the compliance process in relation to directly connected and Embedded Power Stations (subject to a Bilateral Agreement), HVDC Systems, Grid Forming Plant and Network Operator’s or Non-Embedded Customer’s Plant and Apparatus. For the avoidance of doubt, the requirements of the European Compliance Processes do not apply to Demand Response Providers unless they are also an EU Code User and have entered into a CUSC Contract with The Company. Generators in respect of Electricity Storage Modules are required to meet the requirements of this ECC but are not required to satisfy the requirements of Retained EU Law (Commission Regulation (EU) 2016/631, Commission Regulation (EU) 2016/1388 or Commission Regulation (EU) 2016/1485). Any derogation in respect of Electricity Storage Modules would therefore be against the GB Grid Code as the requirements applicable to Electricity Storage Modules are not enforceable by EU Law:

(i) Type A Power Generating Modules:

the process for issuing and receiving an Installation Document which must be followed by The Company and any User with a Type A Power Generating Module to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus prior to the relevant Plant and Apparatus being energised.

(ii) Type B, Type C or Type D Power Generating Modules and HVDC Systems:

the process (leading to an Energisation Operational Notification) which must be followed by The Company and any User with a Type B, Type C or Type D Power Generating Module or HVDC System to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus (including OTSUA) prior to the relevant Plant and Apparatus (including any OTSUA) being energised.

the process (leading to an Interim Operational Notification and Final Operational Notification) which must be followed by The Company and any User with a Type B, Type C or Type D Power Generating Module or HVDC System or HVDC System Owner to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus (including and dynamically controlled OTSUA). This process shall be followed prior to and during the course of the relevant Plant and Apparatus (including OTSUA) being energised and Synchronised.

the process (leading to a Limited Operational Notification) which must be followed by The Company and each User with a Type B, Type C or Type D Power Generating Module or HVDC System where any of its Plant and/or Apparatus (including any OTSUA) becomes unable to comply with relevant provisions of the Grid Code, and where applicable with Appendices F1 to F5 of the Bilateral Agreement (and in the case of OTSUA Appendices OF1 to OF5 of the Bilateral Agreement). This process also includes when changes or Modifications are made to Plant and/or Apparatus (including OTSUA). This process applies to such Plant and/or Apparatus after the Plant and/or Apparatus has become Operational and until Disconnected from the Total System, (or until, in the case of
OTSUA, the OTSUA Transfer Time) when changes or Modifications are made.

(iii) Network Operator’s or Non-Embedded Customer’s Plant and Apparatus:

the process (leading to an Energisation Operational Notification) which must be followed by The Company and any Network Operator or Non-Embedded Customer to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus prior to the relevant Plant and Apparatus being energised.

the process (leading to an Interim Operational Notification and Final Operational Notification) which must be followed by The Company and any Network Operator or Non-Embedded Customer to demonstrate its compliance with the Grid Code in relation to its Plant and Apparatus. This process shall be followed prior to and during the course of the relevant Plant and Apparatus being energised and operated by using the grid connection.

the process (leading to a Limited Operational Notification) which must be followed by The Company and each Network Operator or Non-Embedded Customer where any of its Plant and/or Apparatus becomes unable to comply with relevant provisions of the Grid Code, and where applicable with Appendices F1 to F5 of the Bilateral Agreement. This process also includes changes or Modifications made to the Plant and/or Apparatus. This process applies to such Plant and/or Apparatus after the Plant and/or Apparatus has become operational and until Disconnected from the Transmission System.

ECP.1.2 As used in the ECP, references to OTSUA means OTSUA to be connected or connected to the National Electricity Transmission System prior to the OTSUA Transfer Time.

ECP.1.3 Where a Generator or HVDC System Owner and/or The Company are required to apply for a derogation to the Authority, this is not in respect of OTSUA.

ECP.1.4 In the case of an Electricity Storage Plant comprising of separate generating units and demand taking plant (eg a pump) then compliance would be assessed individually on the generating units and the demand taking elements.

ECP.2 OBJECTIVE

ECP.2.1 The objective of the ECP is to ensure that there is a clear and consistent process for demonstration of compliance by Users with the European Connection Conditions and Bilateral Agreement and will enable The Company to comply with its statutory and Transmission Licence obligations. For the avoidance of doubt, the requirements of the European Compliance Processes do not apply to Demand Response Providers unless they are also an EU Code User and have entered into a CUSC Contract with The Company.

ECP.2.2 Provisions of the ECP which apply in relation to OTSDUW and OTSUA shall (in any particular case) apply up to the OTSUA Transfer Time, whereupon such provisions shall (without prejudice to any prior non-compliance) cease to apply.
ECP.2.3 In relation to OTSDUW, provisions otherwise to be contained in a Bilateral Agreement may be contained in the Construction Agreement, and accordingly a reference in the ECP to a relevant Bilateral Agreement includes the relevant Construction Agreement.

ECP.3 SCOPE

ECP.3.1 The ECP applies to The Company and to Users, which in the ECP means:

(a) EU Generators (other than in relation to Embedded Power Stations not subject to a Bilateral Agreement) including those undertaking OTSDUW.

(b) Network Operators who are either;

(i) EU Code Users in respect of their entire distribution System; or

(ii) GB Code Users in respect of their EU Grid Supply Points only

(c) Non-Embedded Customers who are EU Code Users;

(d) HVDC System Owners (other than those which only have Embedded HVDC Systems not subject to a Bilateral Agreement).

(e) Grid Forming Plant Owners who own and operate a Grid Forming Plant and intend to satisfy the requirements of ECC.6.3.19

ECP.3.2 The above categories of User will become bound by the ECP prior to them generating, distributing, supplying or consuming, or in the case of OTSUA, transmitting, as the case may be, and references to the various categories should, therefore, be taken as referring to them in that prospective role.

ECP.3.3 For the avoidance of doubt, Demand Response Providers do not need to satisfy the requirements of this ECP unless they are also defined as an EU Code User and have a CUSC Contract with The Company. Where a Demand Response Provider is not an EU Code User and does not have a CUSC Contract with The Company, the requirements of the Demand Response Services Code shall only apply.

ECP.3.4 For the avoidance of doubt, this ECP does not apply to GB Code Users other than in respect of Network Operator’s EU Grid Supply Points.

ECP.4 CONNECTION PROCESS

ECP.4.1 The CUSC Contract(s) contain certain provisions relating to the procedure for connection to the National Electricity Transmission System or, in the case of Embedded Power Stations or Embedded HVDC Systems, becoming operational and include provisions to be complied with by Users prior to and during the course of The Company notifying the User that it has the right to become operational. In addition to such provisions, this ECP sets out in further detail the processes to be followed to demonstrate compliance. While this ECP does not expressly address the processes to be followed in the case of OTSUA connecting to a Network Operator’s User System prior to OTSUA Transfer Time, the processes to be followed by The Company and the Generator in respect of the OTSUA in such circumstances shall be
consistent with those set out below by reference to OTSUA directly connected to the National Electricity Transmission System.

ECP.4.2

The provisions contained in ECP.5 to ECP.7 detail the process to be followed in order for the User’s Plant and Apparatus (including OTSUA) to become operational. This process includes

(i) the acceptance of an Installation Document for a Type A Power Generating Module;

(ii) for energisation an EON for Type B, Type C or Type D Power Generating Modules, or HVDC Equipment, Grid Forming Plant or Network Operator’s or Non-Embedded Customer’s Plant and Apparatus;

(iii) for synchronising an ION for Type B, Type C or Type D Power Generating Modules or HVDC Equipment;

(iv) for operating by using the Grid Supply Point an ION for;

   a. Network Operators who are EU Code Users in respect of their entire distribution System;

   b. Network Operators who are GB Code Users in respect of their EU Grid Supply Points only; or

   c. Non-Embedded Customers who are EU Code Users;

(v) for final certification a FON.

ECP.4.2.1

The provisions contained in ECP.5 relate to the connection and energisation of User’s Plant and Apparatus (including OTSUA) to the National Electricity Transmission System or where Embedded, to a User’s System.

ECP.4.2.2

The provisions contained in ECP.6 and ECP.7 provide the process for Generators, HVDC System Owners, Grid Forming Plant Owners, Network Operators and Non-Embedded Customers to demonstrate compliance with the Grid Code and with, where applicable, the CUSC Contract(s) prior to and during the course of such Generator’s, HVDC System Owner’s (including OTSUA up to the OTSUA Transfer Time), Network Operator’s and Non-Embedded Customer’s Plant and Apparatus) becoming operational.

ECP.4.2.3

The provisions contained in ECP.8 detail the process to be followed when:

(a) a Generator’s or HVDC System Owner’s, or Grid Forming Plant Owner’s, or Network Operator’s or Non-Embedded Customer’s Plant and/or Apparatus (including the OTSUA) is unable to comply with any provisions of the Grid Code and Bilateral Agreement; or,

(b) following any notification by a Generator or a HVDC System Owner or a Grid Forming Plant Owner or a Network Operator or a Non-Embedded Customer under the PC of any change to its Plant and Apparatus (including any OTSUA); or,

(c) a Modification to a Generator’s or a HVDC System Owner’s or a Grid Forming Plant Owner’s or a Network Operator’s or a Non-Embedded Customer’s Plant and/or Apparatus.

ECP.4.2.4

For Grid Forming Plant Owners, the Operational Notification Process of this ECP shall apply in relation to the type of Plant to which the Grid Forming Capability is provided (be it a GBGF-S or GBGF-I),

ECP
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ECP.4.3 Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment not subject to a Bilateral Agreement

In the case of Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Systems not subject to a Bilateral Agreement, ensuring the obligations of the ECC and Appendix E of the relevant Bilateral Agreement between The Company and the host Network Operator are performed and discharged by the relevant party. For the avoidance of doubt the process in this ECP does not apply to Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment not subject to a Bilateral Agreement.

ECP.5 ENERGISATION OPERATIONAL NOTIFICATION

ECP.5.1 The following provisions apply in relation to the issue of an Energisation Operational Notification in respect of a Power Station consisting of Type B, Type C or Type D Power Generating Modules or an HVDC System or a Network Operator’s or a Non-Embedded Customer’s Plant and Apparatus.

ECP.5.1.1 Certain provisions relating to the connection and energisation of the User’s Plant and Apparatus at the Connection Site and OTSUA at the Transmission Interface Point and in certain cases of Embedded Plant and Apparatus are specified in the CUSC and/or CUSC Contract(s). For other Embedded Plant and Apparatus, the Distribution Code, the DCUSA and the Embedded Development Agreement for the connection specify equivalent provisions. Further detail on this is set out in ECP.5 below.

ECP.5.2 The items for submission prior to the issue of an Energisation Operational Notification are set out in ECC.5.2.

ECP.5.3 In the case of a Generator or HVDC System Owner the items referred to in ECC.5.2 shall be submitted using the Power Generating Module Document or User Data File Structure as applicable.

ECP.5.4 Not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion, prior to the User wishing to energise its Plant and Apparatus (including passive OTSUA) for the first time, the User will submit to The Company a Certificate of Readiness to Energise High Voltage Equipment which specifies the items of Plant and Apparatus (including OTSUA) ready to be energised in a form acceptable to The Company.

ECP.5.5 If the relevant obligations under the provisions of the CUSC and/or CUSC Contract(s) and the conditions of ECP.5 have been completed to The Company's reasonable satisfaction then The Company shall issue an Energisation Operational Notification. Any dynamically controlled reactive compensation OTSUA (including Statcoms or Static Var Compensators) shall not be Energised until the appropriate Interim Operational Notification has been issued in accordance with ECP.6.

ECP.6 OPERATIONAL NOTIFICATION PROCESSES

ECP.6.1 OPERATIONAL NOTIFICATION PROCESS (Type A)

ECP.6.1.1 The following provisions apply in relation to the notification process in in respect of a Power Station consisting of Type A Power Generating Modules.
ECP.6.1.2  Not less than 7 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator wishing to Synchronise its Plant and Apparatus for the first time, the Generator will:

submit to The Company, a Notification of the User’s Intention to Connect; and

submit to The Company an Installation Document containing at least but not limited to the items referred to at ECP.6.1.3.

ECP.6.1.3  Items for submission prior to connection.

ECP.6.1.3.1  Prior to the issue of an acknowledgment to connect, the Generator must submit to The Company, to The Company’s satisfaction, an Installation Document containing at least but not limited to:

(i)  The location at which the connection is made;

(ii)  The date of the connection;

(iii)  The Maximum Capacity of the installation in kW;

(iv)  The type of primary energy source;

(v)  The classification of the Power Generating Module as an emerging technology;

(vi)  A list of references to Equipment Certificates issued by an authorised certifier or otherwise agreed with The Company used for equipment that is installed at the site or copies of the relevant Equipment Certificates issued by an Authorised Certifier or otherwise where these are relied upon as part of the evidence of compliance;

(vii)  As regards equipment used, for which an Equipment Certificate has not been received, information shall be provided as directed by The Company or the Relevant Network Operator; and

(viii)  The contact details of the Generator and the installer and their signatures.

ECP.6.1.3.2  The items referred to in ECP.6.1.3 shall be submitted by the Generator in the form of an Installation Document for each applicable Power Generating Module.

ECP.6.1.4  No Power Generating Module shall be Synchronised to the Total System until the later of:

(a)  the date specified by the Generator in the Installation Document issued in respect of each applicable Power Generating Module(s); and,

(b)  acknowledgement is received from The Company confirming receipt of the Installation Document.

ECP.6.1.5  When the requirements of ECP.6.1.2 to ECP.6.1.4 have been met, The Company will notify the Generator that the Power Generating Module may (subject to the Generator having fulfilled the requirements of ECP.6.1.3 where that applies) be Synchronised to the Total System.
ECP.6.1.6 Not less than 7 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator wishing to decommission its Plant and Apparatus, the Generator will submit to The Company a Notification of User’s Intention to Disconnect.

ECP.6.2 INTERIM OPERATIONAL NOTIFICATION (Type B and Type C)

ECP.6.2.1 The following provisions apply in relation to the issue of an Interim Operational Notification in respect of a Power Station consisting of Type B and/or Type C Power Generating Modules.

ECP.6.2.2 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator wishing to Synchronise its Plant and Apparatus or dynamically controlled OTSUA for the first time the Generator or HVDC Equipment owner will:

(i) submit to The Company a Notification of User’s Intention to Synchronise; and

(ii) submit to The Company an initial Power Generating Module Document containing at least but not limited to the items referred to at ECP.6.2.3.

ECP.6.2.3 Items for submission prior to issue of the Interim Operational Notification.

ECP.6.2.3.1 Prior to the issue of an Interim Operational Notification in respect of the EU Code User’s Plant and Apparatus or dynamically controlled OTSUA, the Generator must submit to The Company to The Company’s satisfaction an Interim Power Generating Module Document containing at least but not limited to:

(i) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand;

(ii) for Type C Power Generating Modules the simulation models;

(iii) details of any special Power Generating Module(s) protection as required by ECC.6.2.2.3. This may include Pole Slipping protection and islanding protection schemes as applicable;

(iv) simulation study provisions of Appendix ECP.A.3 and the results demonstrating compliance with Grid Code requirements of:

PC.A.5.4.2
PC.A.5.4.3.2,
ECC.6.3.4,
ECC.6.3.7.3.1 to ECC.6.3.7.3.6,
ECC.6.3.15, ECC.6.3.16
ECC.A.6.2.5.6
ECC.A.7.2.3.1

as applicable to the Power Generating Module(s) or dynamically controlled OTSUA unless agreed otherwise by The Company;

(v) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Generator under ECP.7.2 to
demonstrate compliance with relevant Grid Code requirements. Such schedule to be consistent with Appendix ECP.A.5 (in the case of a Synchronous Power Generating Module) or Appendix ECP.A.6 (in the case of a Power Park Modules) and OTSUA as applicable;

(vi) copies of Manufacturer’s Test Certificates or Equipment Certificates issued by an Authorised Certifier or equivalent as agreed with The Company where these are relied upon as part of the evidence of compliance; and

(vii) a Compliance Statement and a User Self Certification of Compliance completed by the EU Code User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Generator has identified that will not or may not be met or demonstrated.

ECP.6.2.3.2 The items referred to in ECP.6.2.3 shall be submitted by the Generator in the form of a Power Generating Module Document (PGMD) for each applicable Power Generating Module.

ECP.6.2.4 No Generating Unit or dynamically controlled OTSUA shall be Synchronised to the Total System (and for the avoidance of doubt, dynamically controlled OTSUA will not be able to transmit) until the later of:

(a) the date specified by The Company in the Interim Operational Notification issued in respect of each applicable Power Generating Module(s) or dynamically controlled OTSUA; and,

(b) in the case of Synchronous Power Generating Module(s) only after the date of receipt by the Generator of written confirmation from The Company that the Synchronous Power Generating Module or CCGT Module as applicable has completed the following tests to demonstrate compliance with the relevant provisions of the Connection Conditions to The Company’s satisfaction:

(i) those tests required to establish the open and short circuit saturation characteristics of the Synchronous Power Generating Module (as detailed in Appendix ECP.A.4.3) to enable assessment of the short circuit ratio in accordance with ECC.6.3.2. Such tests may be carried out at a location other than the Power Station site and supplied in the form of an Equipment Certificate or as otherwise agreed by The Company; and

(ii) open circuit step response tests (as detailed in Appendix ECP.A.5.2) to demonstrate compliance with ECC.A.6.2.4.1.

ECP.6.2.5 The Company shall assess the schedule of tests submitted by the Generator with the Notification of User’s Intention to Synchronise under ECP.6.2.3 and shall determine whether such schedule has been completed to The Company’s satisfaction.

ECP.6.2.6 When the requirements of ECP.6.2.2 to ECP.6.2.5 have been met, The Company will notify the Generator that the: Synchronous Power Generating Module, CCGT Module, Power Park Module or Dynamically controlled OTSUA.
as applicable may (subject to the Generator having fulfilled the requirements of ECP.6.2.3 where that applies) be Synchronised to the Total System through the issue of an Interim Operational Notification. Where the Generator is undertaking OTSDUW then the Interim Operational Notification will be in two parts, with the “Interim Operational Notification Part A” applicable to OTSUA and the Interim Operational Notification Part B” applicable to the EU Code Users Plant and Apparatus. For the avoidance of doubt, the “Interim Operational Notification Part A” and the “Interim Operational Notification Part B” can be issued together or at different times. In respect of an Embedded Power Station or Embedded HVDC Equipment Station (other than an Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment Stations not subject to a Bilateral Agreement), The Company will notify the Network Operator that an Interim Operational Notification has been issued.

ECP.6.2.6.1 The Interim Operational Notification will be time limited, the expiration date being specified at the time of issue. The Interim Operational Notification may be renewed by The Company.

ECP.6.2.6.2 The Generator must operate the Power Generating Module or OTSUA in accordance with the terms, arising from the Unresolved Issues, of the Interim Operational Notification. Where practicable, The Company will discuss such terms with the Generator prior to including them in the Interim Operational Notification.

ECP.6.2.6.3 The Interim Operational Notification will include the following limitations:

(a) In the case of OTSUA, the Interim Operational Notification Part A permits Synchronisation of the dynamically controlled OTSUA to the Total System only for the purposes of active control of voltage and reactive power and not for the purpose of exporting Active Power.

(b) In the case of a Power Park Module the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) will limit the proportion of the Power Park Module which can be simultaneously Synchronised to the Total System such that neither of the following figures is exceeded:

(i) 20% of the Maximum Capacity of the Power Park Module (or the output of a single Power Park Unit where this exceeds 20% of the Power Station’s Maximum Capacity)

until the Generator has completed the voltage control tests (detailed in ECP.A.6.2) (including in respect of any dynamically controlled OTSUA) to The Company’s reasonable satisfaction. Following successful completion of this test each additional Power Park Unit should be included in the voltage control scheme as soon as is technically possible (unless The Company agrees otherwise).

(c) In the case of a Synchronous Power Generating Module employing a static Excitation System the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) may, if applicable, limit the maximum Active Power output and Reactive Power output of the Synchronous Power Generating Module or CCGT module prior to the successful commissioning of the Power System Stabiliser to The Company’s satisfaction, if applicable.
ECP.6.2.6.4 Operation in accordance with the Interim Operational Notification whilst it is in force will meet the requirements for compliance by the Generator and The Company of all the relevant provisions of the European Connection Conditions.

ECP.6.2.7 Other than Unresolved Issues that are subject to tests required under ECP.7.2 to be witnessed by The Company, the Generator must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Generator must liaise with The Company in respect of such resolution. The tests that may be witnessed by The Company are specified in ECP.7.2.

ECP.6.2.8 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator wishing to synchronise its Plant and Apparatus or dynamically controlled OTSUA for the first time the Generator or HVDC System Owner will:

i. submit to The Company a Notification of User’s Intention to Synchronise; and

ii. submit to The Company the items referred to at ECP.6.3.3.

ECP.6.2.9 The items referred to at ECP.7.3 shall be submitted by the Generator after successful completion of the tests required under ECP.7.2.

ECP.6.3 INTERIM OPERATIONAL NOTIFICATION (Type D and HVDC Equipment)

ECP.6.3.1 The following provisions apply in relation to the issue of an Interim Operational Notification in respect of a Power Station consisting of Type D Power Generating Modules or an HVDC System.

ECP.6.3.2 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator or HVDC System Owner wishing to synchronise its Plant and Apparatus or dynamically controlled OTSUA for the first time the Generator or HVDC System Owner will:

i. submit to The Company a Notification of User’s Intention to Synchronise; and

ii. submit to The Company the items referred to at ECP.6.3.3.

ECP.6.3.3 Items for submission prior to issue of the Interim Operational Notification.

ECP.6.3.3.1 Prior to the issue of an Interim Operational Notification in respect of the EU Code User’s Plant and Apparatus or dynamically controlled OTSUA the Generator or HVDC System Owner must submit to The Company to The Company’s satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand;

(b) details of any special Power Generating Module(s) or HVDC Equipment protection as applicable. This may include Pole Slipping protection and islanding protection schemes;

(c) any items required by ECP.5.2, updated by the EU Code User as necessary;
(d) simulation study provisions of Appendix ECP.A.3 and the results demonstrating compliance with Grid Code requirements of:

PC.A.5.4.2
PC.A.5.4.3.2,
ECC.6.3.4,
ECC.6.3.7.3.1 to ECC.6.3.7.3.6,
ECC.6.3.15, ECC.6.3.16
ECC.A.6.2.5.6
ECC.A.7.2.3.1

as applicable to the Power Station, Synchronous Power Generating Module(s), Power Park Module(s), HVDC Equipment or dynamically controlled OTSUA unless agreed otherwise by The Company;

(e) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Generator or HVDC System Owner under ECP.7.2 to demonstrate compliance with relevant Grid Code requirements. Such schedule to be consistent with Appendix ECP.A.5 (in the case of Synchronous Power Generating Modules) or Appendix ECP.A.6 (in the case of Power Park Modules and OTSUA as applicable) or Appendix ECP.A.7 (in the case of HVDC Equipment); and

(f) an interim Compliance Statement and a User Self Certification of Compliance completed by the EU Code User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Generator or HVDC System Owner has identified that will not or may not be met or demonstrated.

ECP.6.3.3.2 The items referred to in ECP.6.3.3 shall be submitted by the Generator or HVDC System Owner using the User Data File Structure.

ECP.6.3.4 No Power Generating Module or HVDC Equipment shall be Synchronised to the Total System (and for the avoidance of doubt, dynamically controlled OTSUA will not be able to transmit) until the later of:

(a) the date specified by The Company in the Interim Operational Notification issued in respect of the Power Generating Module(s) or HVDC Equipment or dynamically controlled OTSUA; and,

(b) if Embedded, the date of receipt of a confirmation from the Network Operator in whose System the Plant and Apparatus is connected that it is acceptable to the Network Operator that the Plant and Apparatus be connected and Synchronised; and,

(c) in the case of Synchronous Power Generating Module(s) only after the date of receipt by Generator of written confirmation from The Company that the Synchronous Power Generating Module has completed the following tests to demonstrate compliance with the relevant provisions of the Connection Conditions to The Company's satisfaction:

(i) those tests required to establish the open and short circuit saturation characteristics of the Synchronous Power Generating Module (as detailed in Appendix ECP.A.5.3) to enable assessment of the short circuit ratio in accordance
with ECC.6.3.2. Such tests may be carried out at a location other than the Power Station site; and

(ii) open circuit step response tests (as detailed in Appendix ECP.A.5.2) to demonstrate compliance with ECC.A.6.2.4.1.

ECP.6.3.5 The Company shall assess the schedule of tests submitted by the Generator or HVDC System Owner with the Notification of User’s Intention to Synchronise under ECP.6.3.1 and shall determine whether such schedule has been completed to The Company’s satisfaction.

ECP.6.3.6 When the requirements of ECP.6.3.2 to ECP.6.3.5 have been met, The Company will notify the Generator or HVDC System Owner that the: Synchronous Power Generating Module, CCGT Module, Power Park Module Dynamically controlled OTSUA or HVDC Equipment

as applicable may (subject to the Generator or HVDC System Owner having fulfilled the requirements of ECP.6.3.3 where that applies) be Synchronised to the Total System through the issue of an Interim Operational Notification. Where the Generator is undertaking OTSDUW then the Interim Operational Notification will be in two parts, with the “Interim Operational Notification Part A” applicable to OTSUA and the “Interim Operational Notification Part B” applicable to the EU Code Users Plant and Apparatus. For the avoidance of doubt, the “Interim Operational Notification Part A” and the “Interim Operational Notification Part B” can be issued together or at different times. In respect of an Embedded Power Station or Embedded HVDC Equipment Station (other than Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment not subject to a Bilateral Agreement), The Company will notify the Network Operator that an Interim Operational Notification has been issued.

ECP.6.3.6.1 The Interim Operational Notification will be time limited, the expiration date being specified at the time of issue. The Interim Operational Notification may be renewed by The Company for up to a maximum of 24 months from the date of the first issue of the Interim Operational Notification. The Company may only issue an extension to an Interim Operational Notification beyond 24 months provided the Generator or HVDC System Owner has applied for a derogation for any remaining Unresolved Issues to the Authority as detailed in ECP.9.

ECP.6.3.6.2 The Generator or HVDC System Owner must operate the Power Generating Module or HVDC Equipment in accordance with the terms, arising from the Unresolved Issues, of the Interim Operational Notification. Where practicable, The Company will discuss such terms with the Generator or HVDC System Owner prior to including them in the Interim Operational Notification.

ECP.6.3.6.3 The Interim Operational Notification will include the following limitations:

(a) In the case of OTSUA, the Interim Operational Notification Part A permits Synchronisation of the dynamically controlled OTSUA to the Total System only for the purposes of active control of voltage and Reactive Power and not for the purpose of exporting Active Power.

(b) In the case of a Power Park Module the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference

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will be to the Interim Operational Notification Part B) will limit the proportion of the Power Park Module which can be simultaneously Synchronised to the Total System such that neither of the following figures is exceeded:

(i) 20% of the Maximum Capacity of the Power Park Module (or the output of a single Power Park Unit where this exceeds 20% of the Power Station’s Maximum Capacity); nor

(ii) 50MW

until the Generator has completed the voltage control tests (detailed in ECP.A.6.3.2) to The Company’s reasonable satisfaction. Following successful completion of this test, each additional Power Park Unit should be included in the voltage control scheme as soon as is technically possible (unless The Company agrees otherwise).

(c) In the case of a Power Park Module with a Maximum Capacity greater or equal to 100MW, the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) will limit the proportion of the Power Park Module which can be simultaneously Synchronised to the Total System to 70% of Maximum Capacity until the Generator has completed the Limited Frequency Sensitive Mode (LFSM-O) control tests with at least 50% of the Maximum Capacity of the Power Park Module in service (detailed in ECP.A.6.3.1) to The Company’s reasonable satisfaction.

(d) In the case of a Synchronous Power Generating Module employing a static Excitation System or a Power Park Module employing a Power System Stabiliser, the Interim Operational Notification (and where OTSDUW Arrangements apply, this reference will be to the Interim Operational Notification Part B) may if applicable limit the maximum Active Power output and Reactive Power output of the Synchronous Power Generating Module or CCGT module prior to the successful commissioning of the Power System Stabiliser to The Company’s satisfaction.

ECP.6.3.6.4 Operation in accordance with the Interim Operational Notification whilst it is in force will meet the requirements for compliance by the Generator or HVDC System Owner and The Company of all the relevant provisions of the European Connection Conditions.

ECP.6.3.7 Other than Unresolved Issues that are subject to tests required under ECP.7.2 to be witnessed by The Company, the Generator or HVDC System Owner must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Generator or HVDC System Owner must liaise with The Company in respect of such resolution. The tests that may be witnessed by The Company are specified in ECP.7.2.

ECP.6.3.8 Not less than 28 days, or such shorter period as may be acceptable in The Company’s reasonable opinion, prior to the Generator or HVDC System Owner wishing to commence tests required under ECP.7 to be witnessed by The Company, the Generator or HVDC System Owner will notify The Company that the Power Generating Module(s) or HVDC Equipment(s) as applicable is ready to commence such tests.
ECP.6.3.9 The items referred to at ECP.7.3 shall be submitted by the Generator or the HVDC System Owner after successful completion of the tests required under ECP.7.2.

ECP.6.4 INTERIM OPERATIONAL NOTIFICATION (Network Operator's or Non-Embedded Customer's Plant and Apparatus)

ECP.6.4.1 The following provisions apply in relation to the issue of an Interim Operational Notification in respect of Network Operator's or Non-Embedded Customer's Plant and Apparatus.

ECP.6.4.2 Not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion, prior to the Network Operator or Non-Embedded Customer wishing to operate its Plant and Apparatus by using the EU Grid Supply Point for the first time, the Network Operator or Non-Embedded Customer will:

i. submit to The Company a Notification of User's Intention to Operate; and

ii. submit to The Company the items referred to at ECP.6.4.3.

ECP.6.4.3 Items for submission prior to issue of the Interim Operational Notification.

ECP.6.4.3.1 Prior to the issue of an Interim Operational Notification in respect of the User's Plant and Apparatus at an EU Grid Supply Point, the Network Operator or Non-Embedded Customer must submit to The Company to The Company's satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with any estimated values assumed for planning purposes confirmed or, where practical, replaced by validated actual values and by updated estimates for the future and by updated forecasts for Forecast Data items such as Demand;

(b) details of any special protection as applicable;

(c) any items required by ECP.5.2, updated as necessary;

(d) data submission and results required by Appendix ECP.A.8 demonstrating compliance with Grid Code requirements of:

PC.A.2.2
PC.A.2.3
PC.A.2.4
PC.A.2.5.2
PC.A.2.5.3
PC.A.2.5.4
PC.A.2.5.6
PC.A.4
PC.A.6.1.3
PC.A.6.3
PC.A.6.7.1

as applicable to the Network Operator's or Non-Embedded Customer's Plant and Apparatus unless agreed otherwise by The Company;

(e) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Network Operator or Non-
Embedded Customer under ECP.7.8 (or Equipment Certificates as relevant) to demonstrate compliance with relevant Grid Code requirements. Such schedule is to be consistent with Appendix ECP.A.8.

(f) an interim Compliance Statement and a User Self Certification of Compliance completed by the User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Network Operator or Non-Embedded Customer has identified that will not or may not be met or demonstrated.

ECP.6.4.4 No Network Operator's or Non-Embedded Customer's Plant and Apparatus shall be operated by using the EU Grid Supply Point until the date specified by The Company in the Interim Operational Notification.

ECP.6.4.5 The Company shall assess the schedule of tests submitted by the Network Operator or Non-Embedded Customer with the Notification of User's Intention to Operate under ECP.6.4.1 and shall determine whether such schedule has been completed to The Company's satisfaction.

ECP.6.4.6 When the requirements of ECP.6.4.2 to ECP.6.4.5 have been met, The Company will notify the Network Operator or Non-Embedded Customer that the Plant and Apparatus may (subject to the Network Operator or Non-Embedded Customer having fulfilled the requirements of ECP.6.4.3 where that applies) be operated by using the EU Grid Supply Point through the issue of an Interim Operational Notification.

ECP.6.4.6.1 The Interim Operational Notification will be time limited, the expiration date being specified at the time of issue. The Interim Operational Notification may be renewed by The Company for up to a maximum of 24 months from the date of the first issue of the Interim Operational Notification. The Company may only issue an extension to an Interim Operational Notification beyond 24 months provided the Network Operator or Non-Embedded Customer has applied for a derogation for any remaining Unresolved Issues to the Authority as detailed in ECP.9.

ECP.6.4.6.2 The Network Operator or Non-Embedded Customer must operate the Plant and Apparatus in accordance with the terms, arising from the Unresolved Issues, of the Interim Operational Notification. Where practicable, The Company will discuss such terms with the Network Operator or Non-Embedded Customer prior to including them in the Interim Operational Notification.

ECP.6.4.7 The Network Operator or Non-Embedded Customer must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Network Operator or Non-Embedded Customer must liaise with The Company in respect of such resolution.

ECP.6.4.8 Not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion, prior to the commencement of the tests, unless The Company agrees to a later resolution. The Network Operator or Non-Embedded Customer wishing to commence tests required under ECP.7.8(e) and ECP.A.8 to be witnessed by The Company the Network Operator or Non-Embedded Customer will notify The Company that the Network Operator or Non-Embedded Customer as applicable is ready to commence such tests.
ECP.7. FINAL OPERATIONAL NOTIFICATION

Final Operational Notification in respect of Generators and HVDC System Owners

ECP.7.1 The following provisions apply in relation to the issue of a Final Operational Notification in respect of a Power Station consisting of Type B, Type C and Type D Power Generating Modules or an HVDC System.

ECP.7.2 Tests to be carried out prior to issue of the Final Operational Notification.

ECP.7.2.1 Prior to the issue of a Final Operational Notification the Generator or HVDC System Owner must have completed the tests specified in this ECP.7.2 to The Company’s satisfaction to demonstrate compliance with the relevant Grid Code provisions.

ECP.7.2.2 In the case of any Power Generating Module, OTSUA (if applicable) or HVDC Equipment these tests will reflect the relevant technical requirements and will comprise one or more of the following:

(a) Reactive capability tests to demonstrate that the Power Generating Module, OTSUA (if applicable) or HVDC Equipment can meet the requirements of ECC.6.3.2. These may be witnessed by The Company on site if there is no metering to The Company Control Centre.

(b) Voltage control system tests to demonstrate that the Power Generating Module, OTSUA (if applicable) or HVDC Equipment can meet the requirements of ECC.6.3.6.3, ECC.6.3.8 and, in the case of a Power Park Module, OTSUA (if applicable) and HVDC Equipment, the requirements of ECC.A.7 or ECC.A.8 and, in the case of Synchronous Power Generating Module and CCGT Module, the requirements of ECC.A.6, and any terms specified in the Bilateral Agreement as applicable. These tests may also be used to validate the Excitation System model (PC.A.5.3) or voltage control system model (PC.A.5.4) as applicable. These tests may be witnessed by The Company.

(c) Governor or frequency control system tests to demonstrate that the Power Generating Module, OTSUA (if applicable) or HVDC Equipment can meet the requirements of ECC.6.3.6.2, ECC.6.3.7, where applicable ECC.A.3, and BC.3.7. In the case of a Type B Power Generating Module only tests BC3 and BC4 in ECP.A.5.8 Figure 2 or ECP.A.6.6 Figure 2 must be completed. The results will also validate the Mandatory Service Agreement required by ECC.8.1. These tests may also be used to validate the governor model (PC.A.5.3) or frequency control system model (PC.A.5.4) as applicable. These tests may be witnessed by The Company.

(d) Fault ride through tests in respect of a Power Station with a Maximum Capacity of 100MW or greater, comprised of one or more Power Park Modules, to demonstrate compliance with ECC.6.3.15, ECC.6.3.16 and ECC.A.4. Where test results from a Manufacturers Data & Performance Report as defined in ECP.10 have been accepted this test will not be required.

(e) Any further tests reasonably required by The Company and agreed with the EU Code User to demonstrate any aspects of compliance with the Grid Code and the CUSC Contracts.
ECP.7.2.3 **The Company**'s preferred range of tests to demonstrate compliance with the **ECCs** are specified in Appendix ECP.A.5 (in the case of **Synchronous Power Generating Modules**) or Appendix ECP.A.6 (in the case of a **Power Park Modules** or OTSUA (if applicable)) or Appendix ECP.A.7 (in the case of **HVDC Equipment**) and are to be carried out by the **EU Code User** with the results of each test provided to **The Company**. The **EU Code User** may carry out an alternative range of tests if this is agreed with **The Company**. **The Company** may agree a reduced set of tests where there is a relevant **Manufacturers Data & Performance Report** as detailed in ECP.10 or an applicable **Equipment Certificate** has been accepted.

ECP.7.2.4 In the case of **Offshore Power Park Modules** which do not contribute to **Offshore Transmission Licensee Reactive Power** capability as described in ECC.6.3.2.5 or ECC.6.3.2.6 or Voltage Control as described in ECC.6.3.8.5 the tests outlined in ECP.7.2.2 (a) and ECP.7.2.2 (b) are not required. However, the offshore **Reactive Power** transfer tests outlined in ECP.A.5.8 shall be completed in their place.

ECP.7.2.5 Following completion of each of the tests specified in this ECP.7.2, **The Company** will notify the **Generator** or **HVDC System Owner** whether, in the opinion of **The Company**, the results demonstrate compliance with the relevant **Grid Code** conditions. When the **Generator** or **HVDC System Owner** submits test results to **The Company**, the **Generator** or **HVDC System Owner** may request **The Company** to advise when the notification is expected to be provided. **The Company** should not unduly delay the notification.

ECP.7.2.6 **The Generator** or **HVDC System Owner** is responsible for carrying out the tests and retains the responsibility for safety and personnel during the test.

ECP.7.3 Items for submission prior to issue of the **Final Operational Notification**

ECP.7.3.1 Prior to the issue of a **Final Operational Notification** the **Generator** or **HVDC System Owner** must submit to **The Company** to **The Company**'s satisfaction:

(a) updated **Planning Code** data (both **Standard Planning Data** and **Detailed Planning Data**), with validated actual values and updated estimates for the future including **Forecast Data** items such as **Demand**;

(b) any items required by ECP.5.2 and ECP.6.2.3 or ECP.6.3.3 as applicable, updated by the **EU Code User** as necessary;

(c) evidence to **The Company**'s satisfaction that demonstrates that the controller models and/or parameters (as required under PC.A.5.3.2(c) option 2, PC.A.5.3.2(d) option 2, PC.A.5.4.2, and/or PC.A.5.4.3.2) supplied to **The Company** provide a reasonable representation of the behaviour of the **EU Code User**'s Plant and Apparatus and OTSUA if applicable;

(d) copies of **Manufacturer's Test Certificates** or **Equipment Certificates** issued by an **Authorised Certifier** or equivalent where these are relied upon as part of the evidence of compliance;

(e) results from the tests required in accordance with ECP.7.2 carried out by the **Generator** to demonstrate compliance with relevant **Grid Code** requirements including the tests witnessed by **The Company**; and
(f) the final Compliance Statement and a User Self Certification of Compliance signed by the EU Code User and a statement of any requirements that the Generator or HVDC System Owner has identified that have not been met together with a copy of the derogation in respect of the same from the Authority.

ECP.7.3.2 The items in ECP.7.3 should be submitted by the Generator (including in respect of any OTSUA if applicable) or HVDC System Owner using the User Data File Structure.

ECP.7.4 If the requirements of ECP.7.2 and ECP.7.3 have been successfully met, The Company will notify the Generator or HVDC System Owner that compliance with the relevant Grid Code provisions has been demonstrated for the Power Generating Module(s), OTSUA if applicable or HVDC Equipment as applicable through the issue of a Final Operational Notification. In respect of an Embedded Power Station or Embedded HVDC Equipment other than an Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment not subject to a Bilateral Agreement, The Company will notify the Network Operator that a Final Operational Notification has been issued.

ECP.7.5 If a Final Operational Notification cannot be issued because the requirements of ECP.7.2 and ECP.7.3 have not been successfully met prior to the expiry of an Interim Operational Notification then the Generator or HVDC System Owner (where licensed in respect of its activities) and/or The Company shall apply to the Authority for a derogation. The provisions of ECP.9 shall then apply.

Final Operational Notification in respect of Network Operator’s and Non-Embedded Customer’s Plant and Apparatus

ECP.7.6 The following provisions apply in relation to the issue of a Final Operational Notification in respect of Network Operators and Non-Embedded Customers Plant and Apparatus.

ECP.7.7 Prior to the issue of a Final Operational Notification the Network Operator and Non-Embedded Customer must have addressed the Unresolved Issues to The Company’s satisfaction to demonstrate compliance with the relevant Grid Code provisions.

ECP.7.8 Prior to the issue of a Final Operational Notification the Network Operator and Non-Embedded Customer must submit to The Company to The Company’s satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data), with validated actual values and updated estimates for the future including Forecast Data items such as Demand;

(b) any items required by ECP.5.2 and ECP.6.4 updated by the User as necessary;

(c) evidence to The Company’s reasonable satisfaction that demonstrates that the models and/or parameters as required under PC.A.2.2, PC.A.2.3, PC.A.2.4, PC.A.2.5, PC.A.4 and PC.A.6 (as applicable), supplied to The Company provide a reasonable representation of the behaviour of the User’s Plant and Apparatus;
(d) copies of Manufacturer’s Test Certificates or Equipment Certificates issued by an Authorised Certifier or equivalent where these are relied upon as part of the evidence of compliance;

(e) results from the tests and simulations required in accordance with ECP.A.8 carried out by the Network Operator or Non-Embedded Customer to demonstrate compliance with relevant Grid Code requirements including any tests witnessed by The Company; and

(f) the final Compliance Statement and a User Self Certification of Compliance signed by the User and a statement of any requirements that the Network Operator or Non-Embedded Customer has identified that have not been met together with a copy of the derogation in respect of the same from the Authority.

ECP.7.9 The items referred to at ECP.7.8 shall be submitted by the Network Operator or Non-Embedded Customer after successful completion of the tests required under ECP.7.8.

ECP.7.10 If the requirements of ECP.7.8 have been successfully met, The Company will notify the Network Operator or Non-Embedded Customer that compliance with the relevant Grid Code provisions has been demonstrated for Network Operators or Non-Embedded Customers Plant and Apparatus as applicable through the issue of a Final Operational Notification.

ECP.7.11 If a Final Operational Notification cannot be issued because the requirements of ECP.7.8 have not been successfully met prior to the expiry of an Interim Operational Notification, then the Network Operator or Non-Embedded Customer and/or The Company shall apply to the Authority for a derogation. The provisions of ECP.9 shall then apply.

ECP.8 LIMITED OPERATIONAL NOTIFICATION

ECP.8.1 Following the issue of a Final Operational Notification for a Power Station consisting of Type B, Type C or Type D Power Generating Module or an HVDC System or Network Operators or Non-Embedded Customers Plant and Apparatus if:

(i) the Generator or HVDC System Owner or Network Operator or Non-Embedded Customer becomes aware, that its Plant and/or Apparatus’ (including OTSUA if applicable) capability to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement is not fully available then the Generator or HVDC System Owner or Network Operator or Non-Embedded Customer shall follow the process in ECP.8.2 to ECP.8.11; or,

(ii) a Network Operator becomes aware, that the capability of Plant and/or Apparatus belonging to an Embedded Power Station or Embedded HVDC Equipment Station (other than Embedded Medium Power Stations not subject to a Bilateral Agreement and Embedded HVDC Equipment Stations not subject to a Bilateral Agreement) is failing to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement, then the Network Operator shall inform The Company and The Company shall inform the Generator or HVDC System Owner to then follow the process in ECP.8.2 to ECP.8.11; or,
The Company becomes aware through monitoring as described in OC5.4, that a Generator or HVDC System Owner Plant and/or Apparatus (including OTSUA if applicable) capability to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement is not fully available then The Company shall inform the other party. Where The Company and the Generator or HVDC System Owner cannot agree from the monitoring as described in OC5.4 whether the Plant and/or Apparatus (including OTSUA if applicable) capability to meet any provisions of the Grid Code or where applicable the Bilateral Agreement is not fully available then The Company shall inform the other party. Where The Company and the Generator or HVDC System Owner cannot agree from the monitoring as described in OC5.4 whether the Plant and/or Apparatus (including OTSUA if applicable) is fully available and/or is compliant with the requirements of the Grid Code and/or the Bilateral Agreement, the parties shall first apply the process in OC5.5.1, before applying the process defined in ECP.8 (LON) if applicable. Where the testing instructed in accordance with OC.5.5.1 indicates that the Plant and/or Apparatus (including OTSUA if applicable) is not fully available and/or is not compliant with the requirements of the Grid Code and/or the Bilateral Agreement, or if the parties so agree, the process in ECP.8.2 to ECP.8.11 shall be followed.

The Company becomes aware that a Network Operator’s or Non-Embedded Customer’s Plant and Apparatus capability to meet any provisions of the Grid Code, or where applicable the Bilateral Agreement, is not fully available then The Company shall inform the other party and the process in ECP.8.2 to ECP.8.11 shall be followed.

ECP.8.2 Immediately upon a Generator, HVDC System Owner, Network Operator or Non-Embedded Customer becoming aware that its Power Generating Module, OTSUA (if applicable), HVDC Equipment or Plant and Apparatus, as applicable may be unable to comply with certain provisions of the Grid Code or (where applicable) the Bilateral Agreement, the Generator, HVDC System Owner Network Operator or Non-Embedded Customer shall notify The Company in writing. Additional details of any operating restrictions or changes in applicable data arising from the potential non-compliance and an indication of the date from when the restrictions will be removed and full compliance demonstrated shall be provided as soon as reasonably practical.

ECP.8.3 If the nature of any unavailability and/or potential non-compliance described in ECP.8.1 causes or can reasonably be expected to cause a material adverse effect on the business or condition of The Company or other Users or the National Electricity Transmission System or any User Systems, then The Company may, notwithstanding the provisions of this ECP.8, follow the provisions of Paragraph 5.4 of the CUSC.

ECP.8.4 Except where the provisions of ECP.8.3 apply, where the restriction notified in ECP.8.2 is not resolved in 28 days, then

(i) the Generator or HVDC System Owner with input from and discussion of conclusions with The Company, and the Network Operator where the Synchronous Power Generating Module, CCGT Module, Power Park Module or Power Station as applicable is Embedded, shall undertake an investigation to attempt to determine the causes of and determine a solution to the non-compliance. Such investigation shall continue for no longer than 56 days. During such investigation, the Generator or HVDC System Owner shall provide to The Company the relevant data which has changed due to the restriction in respect of ECP.7.3.1 as notified to the Generator or HVDC System Owner by The Company as being required to be provided; or
(ii) the **Network Operator** or **Non-Embedded Customer** in discussion with **The Company**, shall undertake an investigation to attempt to determine the causes of and a solution to the non-compliance. Such investigation shall continue for no longer than 56 days. During such investigation the **Network Operator** or **Non-Embedded Customer** shall provide to **The Company** the relevant data which has changed due to the restriction in respect of ECP.7.8 as being required to be provided by **The Company**.

### ECP.8.5 Issue and Effect of LON

#### ECP.8.5.1 Following the issue of a Final Operational Notification, **The Company** will issue to the **Generator**, **HVDC System Owner**, **Network Operator** or **Non-Embedded Customer** a Limited Operational Notification if:

(a) by the end of the 56 day period referred to at ECP.8.4, the investigation has not resolved the non-compliance to **The Company**’s satisfaction; or

(b) **The Company** is notified by a Generator, HVDC System Owner (including OTSUA if applicable), Network Operator or Non-Embedded Customer of a Modification to its Plant and Apparatus; or

(c) **The Company** receives a submission of data, or a statement from a Generator, HVDC System Owner (including OTSUA if applicable), Network Operator or Non-Embedded Customer indicating a change in Plant or Apparatus or settings (including but not limited to governor and excitation control systems) that may in **The Company**’s reasonable opinion, acting in accordance with Good Industry Practice be expected to result in a material change of performance.

In the case of an **Embedded Generator** or **Embedded HVDC System Owner**, **The Company** will issue a copy of the Limited Operational Notification to the **Network Operator**.

#### ECP.8.5.2 The **Limited Operational Notification** will be time limited (in the case of **Type D Power Generating Modules**, **HVDC Systems**, **Network Operator’s** or **Non-Embedded Customer’s Plant** and **Apparatus**) to expire no later than 12 months from the start of the non-compliance or restriction or from reconnection following a change). **The Company** may agree a longer duration in the case of a **Limited Operational Notification** following a Modification or whilst the **Authority** is considering the application for a derogation in accordance with ECP.9.1.

#### ECP.8.5.3 The **Limited Operational Notification** will notify the **Generator**, **HVDC System Owner**, **Network Operator** or **Non-Embedded Customer** of any restrictions on the operation of the **Synchronous Power Generating Module(s)**, **CCGT Module(s)**, **Power Park Module(s)**, OTSUA if applicable, HVDC Equipment or Plant and Apparatus and will specify the **Unresolved Issues**. **The Generator**, **HVDC System Owner**, **Network Operator** or **Non-Embedded Customer** must operate in accordance with any notified restrictions and must resolve the **Unresolved Issues**.

#### ECP.8.5.4 The **User** and **The Company** will be deemed compliant with all the relevant provisions of the **Grid Code** provided operation is in accordance with the **Limited Operational Notification**, whilst it is in force, and that the provisions of and referred to in ECP.8 are complied with.

#### ECP.8.5.5 The **Unresolved Issues** included in a **Limited Operational Notification** will show the extent that the provisions of ECP.7.2 (testing) and ECP.7.3 (final data
ECP.8.5.6

In the case of a change or Modification, the Limited Operational Notification may specify that the affected Plant and Apparatus (including OTSUA if applicable) or associated Synchronous Power Generating Module(s) or Power Park Unit(s) must not be Synchronised or, in the case of Network Operator’s or Non-Embedded Customer’s Plant and Apparatus, operated until all of the following items, that in The Company’s reasonable opinion are relevant, have been submitted to The Company to The Company’s satisfaction:

(a) updated Planning Code data (both Standard Planning Data and Detailed Planning Data);

(b) details of any relevant special Power Station, Synchronous Power Generating Module(s), Power Park Module(s), OTSUA (if applicable), HVDC Equipment Station(s) or Network Operator’s or Non-Embedded Customer’s Plant and Apparatus protection as applicable. This may include Pole Slipping protection and islanding protection schemes; and

(c) simulation study provisions of Appendix ECP.A.3 or Appendix ECP.A.8 as appropriate and the results demonstrating compliance with Grid Code requirements relevant to the change or Modification as agreed by The Company; and

(d) a detailed schedule of the tests and the procedures for the tests required to be carried out by the Generator, HVDC Equipment Station, Network Operator or Non-Embedded Customer to demonstrate compliance with relevant Grid Code requirements as agreed by The Company. The schedule of tests shall be consistent with Appendix ECP.A.5, Appendix ECP.A.6 or Appendix ECP.A.8 as appropriate; and

(e) an interim Compliance Statement and a User Self Certification of Compliance completed by the User (including any Unresolved Issues) against the relevant Grid Code requirements including details of any requirements that the Generator, HVDC System Owner, Network Operator or Non-Embedded Customer has identified that will not or may not be met or demonstrated; and

(f) any other items specified in the LON.

ECP.8.5.7

The items referred to in ECP.8.5.6 shall be submitted by the Generator (including in respect of any OTSUA if applicable) or HVDC System Owner using the User Data File Structure or Power Generation Module Document as applicable.

ECP.8.5.8

In the case of Synchronous Power Generating Module(s) only, the Unresolved Issues of the LON may require that the Generator must complete the following tests to The Company’s satisfaction to demonstrate compliance with the relevant provisions of the ECCs prior to the Synchronous Power Generating Module being Synchronised to the Total System:
(a) those tests required to establish the open and short circuit saturation characteristics of the Synchronous Power Generating Module (as detailed in Appendix ECP.A.5.3) to enable assessment of the short circuit ratio in accordance with ECC.6.3.2.3.4 or ECC.6.3.2.5. Such tests may be carried out at a location other than the Power Station site; and

(b) open circuit step response tests (as detailed in Appendix ECP.A.5.2) to demonstrate compliance with ECC.A.6.2.4.1.

ECP.8.6 In the case of a change or Modification, not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion:

(a) prior to the Generator or HVDC System Owner (including OTSUA if applicable) wishing to Synchronise its Plant and Apparatus for the first time following the change or Modification, the Generator or HVDC System Owner will:

(i) submit a Notification of User's Intention to Synchronise; and

(ii) submit to The Company the items referred to at ECP.8.5.6.

(b) prior to the Network Operator or Non-Embedded Customer wishing to operate its Plant and Apparatus for the first time following the change or Modification, the Network Operator or Non-Embedded Customer will;

(i) submit a Notification of User's intention to operate; and

(ii) submit to The Company the items referred to at ECP.8.5.6

ECP.8.7 Other than Unresolved Issues that are subject to tests to be witnessed by The Company, the Generator, HVDC System Owner, Network Operator or Non-Embedded Customer must resolve any Unresolved Issues prior to the commencement of the tests, unless The Company agrees to a later resolution. The Generator, HVDC System Owner, Network Operator or Non-Embedded Customer must liaise with The Company in respect of such resolution. The tests that may be witnessed by The Company are specified in ECP.7.2.2.

ECP.8.8 Not less than 28 days, or such shorter period as may be acceptable in The Company's reasonable opinion, prior to the Generator or HVDC System Owner wishing to commence tests listed as Unresolved Issues to be witnessed by The Company, the Generator or HVDC System Owner will notify The Company that the Synchronous Power Generating Module(s), CCGT Module(s), Power Park Module(s), OTSUA if applicable or HVDC Equipment as applicable is ready to commence such tests.

ECP.8.9 The items referred to at ECP.7.3 or ECP.7.8 as applicable and listed as Unresolved Issues shall be submitted by the Generator, HVDC System Owner, Network Operator or Embedded Customer after successful completion of the tests.

ECP.8.10 Where the Unresolved Issues have been resolved a Final Operational Notification will be issued to the User.

ECP.8.11 If a Final Operational Notification has not been issued by The Company as referred to at ECP.8.5.2 (or where agreed following a Modification by the expiry time of the LON) then the Generator, HVDC System Owner, Network Operator or Non-Embedded Customer (where licensed in respect of its activities) and The Company shall apply to the Authority for a derogation.
ECP.9 PROCESSES RELATING TO DEROGATIONS

ECP.9.1 Whilst the Authority is considering the application for a derogation, the Interim Operational Notification or Limited Operational Notification will be extended to remain in force until the Authority has notified The Company and the Generator, HVDC System Owner, Network Operator or Non-Embedded Customer of its decision. Where the Generator or HVDC System Owner is not licensed, The Company may propose any necessary changes to the Bilateral Agreement with such unlicensed Generator or HVDC System Owner.

ECP.9.2 If the Authority:

(a) grants a derogation in respect of the Plant and/or Apparatus, then The Company shall issue Final Operational Notification once all other Unresolved Issues are resolved; or
(b) decides a derogation is not required in respect of the Plant and/or Apparatus then The Company will reconsider the relevant Unresolved Issues and may issue a Final Operational Notification once all other Unresolved Issues are resolved; or
(c) decides not to grant any derogation in respect of the Plant and/or Apparatus, then there will be no Operational Notification in place and The Company and the User shall consider its rights pursuant to the CUSC.

ECP.9.3 Where an Interim Operational Notification or Limited Operational Notification is so conditional upon a derogation and such derogation includes any conditions (including any time limit to such derogation) the Generator, HVDC System Owner, Network Operator or Non-Embedded Customer will progress the resolution of any Unresolved Issues and / or progress and / or comply with any conditions upon such derogation and the provisions of ECP.6 to ECP.7.11 shall apply and shall be followed.

ECP.10 MANUFACTURER'S DATA & PERFORMANCE REPORT

ECP.10.1.1 Data and performance characteristics in respect of certain Grid Code requirements may be registered with The Company by Power Park Unit manufacturers in respect of specific models of Power Park Units by submitting information in the form of a Manufacturer's Data and Performance Report to The Company.

ECP.10.1.2 A Generator planning to construct a new Power Station containing the appropriate version of Power Park Units in respect of which a Manufacturer's Data & Performance Report has been submitted to The Company may reference the Manufacturer's Data & Performance Report in its submissions to The Company. Any Generator considering referring to a Manufacturer's Data & Performance Report for any aspect of its Plant and Apparatus may contact The Company to discuss the suitability of the relevant Manufacturer's Data & Performance Report to its project to determine if, and to what extent, the data included in the Manufacturer's Data & Performance Report contributes towards demonstrating compliance with those aspects of the Grid Code applicable to the Generator. The Company will inform the Generator if the reference to the Manufacturer's Data & Performance Report is not appropriate or not sufficient for its project.

ECP.10.1.3 The process to be followed by Power Park Unit manufacturers submitting a Manufacturer's Data & Performance Report is agreed by The Company.
ECP.10.2 indicates the specific Grid Code requirement areas in respect of which a Manufacturer’s Data & Performance Report may be submitted.

ECP.10.4 The Company will maintain and publish a register of those Manufacturer’s Data & Performance Reports which The Company has received and accepted as being an accurate representation of the performance of the relevant Plant and / or Apparatus. Such register will identify the manufacturer, the model(s) of Power Park Unit(s) to which the report applies and the provisions of the Grid Code in respect of which the report contributes towards the demonstration of compliance. The inclusion of any report in the register does not in any way confirm that any Power Park Modules which utilise any Power Park Unit(s) covered by a report is or will be compliant with the Grid Code.

ECP.10.2 A Manufacturer’s Data & Performance Report in respect of Power Park Units may cover one (or part of one) or more of the following provisions of the Grid Code:

(a) Fault Ride Through capability ECC.6.3.15, ECC.6.3.16.

(b) Power Park Module mathematical model PC.A.5.4.2.

ECP.10.3 Reference to a Manufacturer’s Data & Performance Report in a EU Code User’s submissions does not by itself constitute compliance with the Grid Code.

ECP.10.4 A Generator referencing a Manufacturer’s Data & Performance Report should insert the relevant Manufacturer’s Data & Performance Report reference in the appropriate place in the DRC data submission, Power Generating Module Document and / or in the User Data File Structure. The Company will consider the suitability of a Manufacturer’s Data & Performance Report:

(a) in place of DRC data submissions, a mathematical model suitable for representation of the entire Power Park Module as per ECP.A.3.4.4. For the avoidance of doubt only the relevant sections as specified in PC.A.2.5.5.7 apply. Site specific parameters will still need to be submitted by the Generator.

(b) Not Used.

(c) to reduce the scope of compliance site tests as follows;

(i) Where there is a Manufacturer’s Data & Performance Report in respect of a Power Park Unit which covers Fault Ride Through, The Company may agree that no Fault Ride Through testing is required.

ECP.10.5 It is the responsibility of the EU Code User to ensure that the correct reference for the Manufacturer’s Data & Performance Report is used and the EU Code User by using that reference accepts responsibility for the accuracy of the information. The EU Code User shall ensure that the manufacturer has kept The Company informed of any relevant variations in plant specification since the submission of the relevant Manufacturer’s Data & Performance Report which could impact on the validity of the information.

ECP.10.6 The Company may contact the Power Park Unit manufacturer directly to verify the relevance of the use of such Manufacturer’s Data & Performance
Report. If The Company believe the use some or all of such Manufacturer’s Data & Performance Report information is incorrect or the referenced data is inappropriate, then the reference to the Manufacturer’s Data & Performance Report may be declared invalid by The Company. Where, and to the extent possible, the data included in the Manufacturer’s Data & Performance Report is appropriate, the compliance assessment process will be continued using the data included in the Manufacturer’s Data & Performance Report.

In the case of a co-located site, for example Electricity Storage Modules or Grid Forming Plant connected within a new or existing Power Station, The Company will accept demonstration of compliance at the Grid Entry Point or User System Entry Point (if Embedded) through a combination of the capabilities of the Power Generating Modules and Electricity Storage Modules (which could include Grid Forming Plant) or Electricity Storage Modules and Generating Units or Power Park Modules (which could include Grid Forming Plant). Generators or Grid Forming Plant Owners should however be aware that for the purposes of compliance, full Grid Code compliance should be demonstrated when, for example, the Electricity Storage Module or Grid Forming Plant is out of service and the remaining Power Generating Module is in service or the Electricity Storage Module or Grid Forming Plant is in service and the Power Generating Module is out of service. Equally, The Company will accept Manufacturer’s Data & Performance Reports for the purposes of proving compliance at co-located sites.

APPENDIX 1
NOT USED
APPENDIX 2

USER SELF CERTIFICATION OF COMPLIANCE (Interim/Final)

<table>
<thead>
<tr>
<th>Power Station/ HVDC Equipment Station</th>
<th>User:</th>
<th>Maximum Capacity (MW) of Plant:</th>
</tr>
</thead>
<tbody>
<tr>
<td>[Name of Connection Site/site of connection]</td>
<td>[Full User name]</td>
<td></td>
</tr>
</tbody>
</table>

This User Self Certification of Compliance records the compliance by the EU Code User in respect of [NAME] Power Station/HVDC Equipment Station with the Grid Code and the requirements of the Bilateral Agreement and Construction Agreement dated [ ] with reference number [ ]. It is completed by the Power Station/HVDC System Owner in the case of Plant and/or Apparatus connected to the National Electricity Transmission System and for Embedded Plant.

We have recorded our compliance against each requirement of the Grid Code which applies to the Power Station/HVDC Equipment Station, together with references to supporting evidence and a commentary where this is appropriate, and have provided this to The Company. A copy of the Compliance Statement is attached.

Supporting evidence, in the form of simulation results, test results, manufacturer’s data and other documentation, is attached in the User Data File Structure.

The EU Code User hereby certifies that, to the best of its knowledge and acting in accordance with Good Industry Practice, the Power Station is compliant with the Grid Code and the Bilateral Agreement in all aspects [with the following Unresolved Issues*] [with the following derogation(s)**]:

<table>
<thead>
<tr>
<th>Connection Condition</th>
<th>Requirement</th>
<th>Ref:</th>
<th>Issue</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Compliance certified by:  
Name: [PERSON]  
Signature: [PERSON]  
Date: [ ]

Title: [PERSON DESIGNATION]  
Of [User details]

* Include for Interim User Self Certification of Compliance ahead of Interim Operational Notification.  
** Include for final User Self Certification of Compliance ahead of Final Operational Notification where derogation(s) have been granted. If no derogation(s) required delete wording and Table.
APPENDIX 3

SIMULATION STUDIES

ECP.A.3.1 SCOPE

ECP.A.3.1.1 This Appendix sets out the simulation studies required to be submitted to The Company to demonstrate compliance with the European Connection Conditions unless otherwise agreed with The Company. This Appendix should be read in conjunction with ECP.6 with regard to the submission of the reports to The Company. Where there is any inconsistency in the technical requirements in respect of which compliance is being demonstrated by simulation in this Appendix and ECC.6.3 and the Bilateral Agreement, the provisions of the Bilateral Agreement and ECC.6.3 prevail. The studies specified in this Appendix will normally be sufficient to demonstrate compliance. However, The Company may agree an alternative set of studies proposed by the Generator or HVDC System Owner provided The Company deem the alternative set of studies sufficient to demonstrate compliance with the Grid Code and the Bilateral Agreement.

ECP.A.3.1.2 The Generator or HVDC System Owner shall submit simulation studies in the form of a report to demonstrate compliance. In all cases the simulation studies must utilise models applicable to the Synchronous Power Generating Module, HVDC Equipment or Power Park Module with proposed or actual parameter settings. Reports should be submitted in English with all diagrams and graphs plotted clearly with legible axes and scaling provided to ensure any variations in plotted values is clear. In all cases, the simulation studies must be presented over a sufficient time period to demonstrate compliance with all applicable requirements.

ECP.A.3.1.3 In the case of an Offshore Power Station where OTSDUW Arrangements apply simulation studies, the Generator should include the action of any relevant OTSUA where applicable to demonstrate compliance with the Grid Code and the Bilateral Agreement at the Interface Point.

ECP.A.3.1.4 The Company will permit relaxation from the requirement ECP.A.3.2 to ECP.A.3.8 where an Equipment Certificate for the Power Generating Module or HVDC Equipment has been provided which details the characteristics from appropriate simulations on a representative installation with the same equipment and settings and the performance of the Power Generating Module or HVDC Equipment can, in The Company’s opinion, reasonably represent that of the installed Power Generating Module or HVDC Equipment.

ECP.A.3.1.5 For Type B, Type C and Type D Power Generating Modules the relevant Equipment Certificate must be supplied in the Power Generating Module Document or Users Data File structure as applicable. For HVDC Equipment the relevant Equipment Certificates must be supplied in the Users Data File structure.

ECP.A.3.1.6 In the case of a co-located site, for example Electricity Storage Modules or Grid Forming Plant connected within a new or existing Power Station, The Company will accept simulation studies to demonstrate compliance at the Grid Entry Point or User System Entry Point (if Embedded) through a combination of the capabilities of the Power Generating Modules (which could include Grid Forming Plant) and Electricity Storage Modules or Electricity Storage Modules (which could include Grid Forming Plant) and Generating Units or Power Park Modules. Generators should however be aware that for the purposes of simulations, full Grid Code compliance should be demonstrated when, for example, the Electricity Storage Module or Grid
Forming Plant is out of service and the remaining Power Generating Module is in service or the Electricity Storage Module or Grid Forming Plant is in service and the Power Generating Module is out of service.

ECP.A.3.2 Power System Stabiliser Tuning

ECP.A.3.2.1 In the case of a Synchronous Power Generating Module with an Excitation System Power System Stabiliser the Power System Stabiliser tuning simulation study report required by ECC.A.6.2.5.6 or required by the Bilateral Agreement shall contain:

(i) the Excitation System model including the Power System Stabiliser with settings as required under the Planning Code (PC.A.5.3.2(c)).

(ii) open circuit time series simulation study of the response of the Excitation System to a +10% step change from 90% to 100% terminal voltage.

(iii) on load time series dynamic simulation studies of the response of the Excitation System with and without the Power System Stabiliser to 2% and 10% steps in the reference voltage and a three phase short circuit fault applied to the higher voltage side of the Synchronous Power Generating Module transformer for 100ms. The simulation studies should be carried out with the Synchronous Power Generating Module operating at full Active Power and maximum leading Reactive Power import with the fault level at the Supergrid HV connection point at minimum or as otherwise agreed with The Company. The results should show the Synchronous Power Generating Module field voltage, terminal voltage, Power System Stabiliser output, Active Power and Reactive Power output.

(iv) gain and phase Bode diagrams for the open loop frequency domain response of the Synchronous Power Generating Module Excitation System with and without the Power System Stabiliser. These should be in a suitable format to allow assessment of the phase contribution of the Power System Stabiliser and the gain and phase margin of the Excitation System with and without the Power System Stabiliser in service.

(v) an eigenvalue plot to demonstrate that all modes remain stable when the Power System Stabiliser gain is increased by at least a factor of 3 from the designed operating value.

(vi) gain Bode diagram for the closed loop on load frequency domain response of the Synchronous Power Generating Module Excitation System with and without the Power System Stabiliser. The Synchronous Power Generating Module operating at full load and at unity power factor. These diagrams should be in a suitable format to allow comparison of the Active Power damping across the frequency range specified in ECC.A.6.2.6.3 with and without the Power System Stabiliser in service.

In the case of a Synchronous Power Generating Module that may operate as Demand (e.g. Pump Storage) the on-load simulations (ii) to (vi) should also carried out in both modes of operation.

ECP.A.3.2.2 In the case of Onshore Non-Synchronous Power Generating Module, Onshore HVDC Equipment and Onshore Power Park Modules and
OTSDUW Plant and Apparatus at the Interface Point the Power System Stabiliser tuning simulation study report required by ECC.A.7.2.4.1 or ECC.A.8.2.4 or required by the Bilateral Agreement shall contain:

(i) the Voltage Control System model including the Power System Stabiliser with settings as required under the Planning Code (PC.A.5.4) and Bilateral Agreement.

(ii) on load time series dynamic simulation studies of the response of the Voltage Control System with and without the Power System Stabiliser to 2% and 10% steps in the reference voltage and a three phase short circuit fault applied to the Grid Entry Point or the Interface Point in the case of OTSDUW Plant and Apparatus for 100ms. The simulation studies should be carried out operating at full Active Power and maximum leading Reactive Power import condition with the fault level at the Supergrid HV connection point at minimum or as otherwise agreed with The Company. The results should show appropriate signals to demonstrate the expected damping performance of the Power System Stabiliser.

(iii) any other simulation as specified in the Bilateral Agreement or agreed between the Generator or HVDC System Owner or Offshore Transmission Licensee and The Company.

ECP.A.3.3 Reactive Capability across the Voltage Range

ECP.A.3.3.1 (a) For a Synchronous Power Generating Module, the Generator shall supply simulation studies to demonstrate the capability to meet ECC.6.3.2 by submission of a report containing load flow simulation study results to demonstrate:

(i) the maximum lagging Reactive Power capability at Maximum Capacity when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in the case of OTSUA) voltage is at 105% of nominal.

(ii) the maximum leading Reactive Power capability at Maximum Capacity when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in the case of OTSUA) voltage is at 95% of nominal.

(iii) the maximum lagging Reactive Power capability at the Minimum Stable Operating Level when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in the case of OTSUA) voltage is at 105% of nominal.

(iv) the maximum leading Reactive Power capability at the Minimum Stable Operating Level when the Grid Entry Point or User System Entry Point if Embedded or Interface Point (in the case of OTSUA) voltage is at 95% of nominal.

(b) For an OSTUA with an Interface Point above 33kV or Power Park Modules with a Grid Entry Point or User System Entry Point above 33kV, the Generator shall demonstrate the capability to meet ECC.6.3.2 by submission of a report containing load flow simulation study results to demonstrate operation at points A, B, E and F in accordance with Figure ECC.A.7.2.2(b) or Figure ECC.A.8.2.2(b). The studies should be run with both the OTSUA and Power Park Module operating at Maximum Capacity and at the Minimum Stable Operating Level.
(c) For an **OSTUA** with an **Interface Point** at or below 33kV or **Power Park Modules** with a **Grid Entry Point** or **User System Entry Point** at or below 33kV, a load flow simulation study results to demonstrate operation at points A, B, E and F in accordance with Figure ECC.A.7.2.2(c) or Figure ECC.A.8.2.2(b). The studies should be run with both the **OTSUA** and **Power Park Module** operating at **Maximum Capacity** and at the **Minimum Stable Operating Level**.

(d) For an **HVDC system**, the **HVDC System Owner** shall supply simulation studies to demonstrate the capability to meet ECC.6.3.2 by submission of a report containing load flow simulation study results to demonstrate operation at points A, B, E and F in accordance with Figure ECC.A.7.2.2(b). The studies should be run with both the **HVDC System operating at the Maximum HVDC Active Power Transmission Capacity and Minimum HVDC Active Power Transmission Capacity**.

ECP.A.3.3.2 In the case of a **Synchronous Power Generating Module** the terminal voltage in the simulation should be the nominal voltage for the machine.

ECP.A.3.3.3 In the case of a **Power Park Module** where the load flow simulation studies show that the individual **Power Park Units** deviate from nominal voltage to meet the **Reactive Power** requirements then evidence must be provided from factory (e.g. in a **Manufacturer's Data & Performance Report**) or site testing that the **Power Park Unit** is capable of operating continuously at the operating points determined in the load flow simulation studies.

ECP.A.3.4 Voltage Control and Reactive Power Stability

ECP.A.3.4.1 This section applies to **HVDC Equipment**; and **Type C & Type D Power Park Modules** to demonstrate the voltage control capability and **Type B Power Park Modules** to demonstrate the voltage control capability if specified by **The Company**.

In the case of a **Power Station** containing **Power Park Modules** and/or **OTSUA**, the **Generator** shall provide a report to demonstrate the dynamic capability and control stability of the **Power Park Module**. The report shall contain:

(i) a dynamic time series simulation study result of a sufficiently large negative step in **System** voltage to cause a change in **Reactive Power** from zero to the maximum lagging value at **Rated MW**.

(ii) a dynamic time series simulation study result of a sufficiently large positive step in **System** voltage to cause a change in **Reactive Power** from zero to the maximum leading value at **Rated MW**.

(iii) a dynamic time series simulation study result to demonstrate control stability at the lagging **Reactive Power** limit by application of a -2% voltage step while operating within 5% of the lagging **Reactive Power** limit.

(iv) a dynamic time series simulation study result to demonstrate control stability at the leading **Reactive Power** limit by application of a +2% voltage step while operating within 5% of the leading **Reactive Power** limit.
(v) a dynamic time series simulation study result of a sufficiently large negative step in System voltage to cause a change in Reactive Power from the maximum leading value to the maximum lagging value at Rated MW.

The Generator should also provide the voltage control study specified in ECP.A.3.7.4.

ECP.A.3.4.2 All the above studies should be completed with a network operating at the voltage applicable for zero Reactive Power transfer at the Grid Entry Point or User System Entry Point if Embedded or, in the case of OTSUA, Interface Point unless stated otherwise. The fault level at the HV connection point should be set at the minimum level as agreed with The Company.

ECP.A.3.5 Fault Ride Through and Fast Fault Current Injection

ECP.A.3.5.1 This section applies to Type B, Type C and Type D Power Generating Modules and HVDC Equipment to demonstrate the modules Fault Ride Through and Fast Fault Current injection capability.

The Generator or HVDC System Owner shall supply time series simulation study results to demonstrate the capability of Synchronous Power Generating Module, HVDC Equipment, and Power Park Modules and OTSUA to meet ECC.6.3.15 and ECC.6.3.16 by submission of a report containing:

(i) a time series simulation study of a 140ms three phase short circuit fault with a retained voltage as detailed in table A.3.5.1 below applied at the Grid Entry Point or (User System Entry Point if Embedded) of the Power Generating Module or HVDC Equipment or OTSUA.

(ii) a time series simulation study of 140ms unbalanced short circuit faults with a retained voltage as detailed in table 1 on the faulted phase(s) applied at the Grid Entry Point or (User System Entry Point if Embedded) of the Power Generating Module or HVDC Equipment or OTSUA. The unbalanced faults to be simulated are:

1. a phase to phase fault
2. a two phase to earth fault
3. a single phase to earth fault.

<table>
<thead>
<tr>
<th>Power Generating Module</th>
<th>Retained Voltage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous Power Generating Module</td>
<td></td>
</tr>
<tr>
<td>Type B</td>
<td>30%</td>
</tr>
<tr>
<td>Type C or Type D with Grid connection point voltage &lt;110kV</td>
<td>10%</td>
</tr>
<tr>
<td>Type D with connection point voltage &gt;110kV</td>
<td>0%</td>
</tr>
<tr>
<td>Power Park Module</td>
<td></td>
</tr>
<tr>
<td>Type B or Type C or Type D with connection point voltage &lt; 110kV</td>
<td>10%</td>
</tr>
<tr>
<td>Type D with connection point voltage &gt;110kV</td>
<td>0%</td>
</tr>
<tr>
<td>HVDC Equipment</td>
<td>0%</td>
</tr>
</tbody>
</table>

Table A.3.5.1

For a Power Generating Module or HVDC Equipment or OTSUA the simulation study should be completed with the Power Generating Module or HVDC Equipment or OTSUA operating at full Active Power and maximum leading Reactive Power and the fault level at
the Supergrid HV connection point at minimum or as otherwise agreed with The Company as detailed in ECC.6.3.15.8.

(iii) time series simulation studies of balanced Supergrid voltage dips applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the Synchronous Power Generating Module or OTSUA. The simulation studies should include:

1. 50% retained voltage lasting 0.45 seconds
2. 70% retained voltage lasting 0.81 seconds
3. 80% retained voltage lasting 1.00 seconds
4. 85% retained voltage lasting 180 seconds.

For a Synchronous Power Generating Module or OTSUA, the simulation study should be completed with the Synchronous Power Generating Module or OTSUA operating at full Active Power and zero Reactive Power output and the fault level at the Supergrid HV connection point at minimum or as otherwise agreed with The Company. Where the Synchronous Power Generating Module is Embedded, the minimum Network Operator’s System impedance to the Supergrid HV Connection Point shall be used which may be calculated from the maximum fault level at the User System Entry Point.

(iv) time series simulation studies of balanced Supergrid voltage dips applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the HVDC Equipment or Power Park Module. The simulation studies should include:

1. 30% retained voltage lasting 0.384 seconds
2. 50% retained voltage lasting 0.71 seconds
3. 80% retained voltage lasting 2.5 seconds
4. 85% retained voltage lasting 180 seconds.

For Power Park Modules, the simulation study should be completed with the HVDC Equipment or Power Park Module operating at full Active Power and zero Reactive Power output and the fault level at the Supergrid HV Connection Point at minimum or as otherwise agreed with The Company. Where the Power Park Module is Embedded, the minimum Network Operator’s System impedance to the Supergrid HV Connection Point shall be used which may be calculated from the maximum fault level at the User System Entry Point.

(v) time series simulation studies of balanced Supergrid voltage dips applied on the nearest point of the National Electricity Transmission System operating at Supergrid voltage to the HVDC Equipment. The simulation studies should include:

1. 30% retained voltage
2. 50% retained voltage
3. 80% retained voltage
4. 85% retained voltage

For HVDC Equipment, the simulation study should be completed with the HVDC Equipment operating at full Active Power transfer and zero Reactive Power output and the fault level at the Supergrid HV connection point at minimum or as otherwise agreed with The Company. Where the HVDC Equipment is Embedded, the minimum Network Operator’s System impedance to the Supergrid HV connection point at minimum or as otherwise agreed with The Company. Where the HVDC Equipment is Embedded, the minimum Network Operator’s System impedance to the Supergrid HV connection point at minimum or as otherwise agreed with The Company.
connection point shall be used which may be calculated from the maximum fault level at the User System Entry Point.

For HVDC Equipment the duration of each voltage dip 1 to 4 above should demonstrate the requirements of the Bilateral Agreement.

ECP.A.3.5.2 Not Used.

ECP.A.3.6 **Limited Frequency Sensitive Mode – Over Frequency (LFSM-O)**

ECP.A.3.6.1 This section applies to Type B, Type C and Type D Power Generating Modules, HVDC Equipment to demonstrate the capability to modulate Active Power at high frequency as required by ECC6.3.7.3.5(ii).

ECP.A.3.6.2 The simulation study should comprise of a Power Generating Module or HVDC Equipment connected to the total System with a local load shown as “X” in figure ECP.A.3.6.1. The load “X” is in addition to any auxiliary load of the Power Station connected directly to the Power Generating Module or HVDC Equipment and represents a small portion of the System to which the Power Generating Module or HVDC Equipment is attached. The value of “X” should be the minimum for which the Power Generating Module or HVDC Equipment can control the power island Frequency to less than 52Hz consistent with ECC.6.3.7.3.5(ii). Where transient excursions above 52Hz occur the Generator or HVDC Equipment Owner should ensure that the duration above 52Hz is less than any high Frequency protection system applied to the Power Generating Module or HVDC Equipment.

ECP.A.3.6.3 For HVDC Equipment and Power Park Modules consisting of units connected wholly by power electronic devices the simulation methodology may be modified by the addition of a Synchronous Power Generating Module (G2) connected as indicated in Figure ECP.A.3.6.2. This additional Synchronous Power Generating Module should have an inertia constant of 3.5MWs/MVA, be initially operating at rated power output and unity Power Factor. The mechanical power of the Synchronous Power Generating Module (G2) should remain constant throughout the simulation.

ECP.A.3.6.4 At the start of the simulation study the Power Generating Module or HVDC Equipment will be operating maximum Active Power output. The Power Generating Module or HVDC Equipment will then be islanded from the Total System but still supplying load “X” by the opening of a breaker, which is not the Power Generating Module or HVDC Equipment connection circuit breaker (the governor should therefore, not receive any signals that the breaker has opened other than the reduction in load and subsequent increase in speed). A schematic arrangement of the simulation study is illustrated by Figure ECP.A.3.6.1.
ECP.A.3.6.5 A simulation study shall be performed for **Type B, C & D Power Generating Modules in Limited Frequency Sensitive Mode (LFSM)** and **Frequency Sensitive Mode (FSM)** for **Type C & D Power Generating Modules**. The simulation study results should indicate **Active Power** and **Frequency**.

ECP.A.3.6.6 To allow validation of the model used to simulate load rejection in accordance with ECC.6.3.7.3.5 as described, a further simulation study is required to represent the largest positive **Frequency** injection step or fast ramp (BC1 and BC3 of Figure 2) that will be applied as a test as described in ECP.A.5.8 and ECP.A.6.6.

**Limited Frequency Sensitive Mode – Under Frequency (LFSM-U)**

ECP.A.3.6.7 This section applies to:
- **Synchronous Power Generating Modules, Type C & D**;
- **HVDC Equipment**;
- **Power Park Modules, Type C & D** to demonstrate the modules capability to modulate Active Power at low frequency.

ECP.A.3.6.8 To demonstrate the **LFSM-U** low **Frequency** control when operating in **Limited Frequency Sensitive Mode** the **Generator** or **HVDC System Owner** shall submit a simulation study representing the response of the **Power Generating Module** or **HVDC Equipment** operating at **80% of Maximum Capacity**. The simulation study event shall be equivalent to:

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**Figure ECP.A.3.6.1 – Diagram of Load Rejection Study**

**Figure ECP.A.3.6.2 – Addition of Generator G2 if applicable**

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**Notes:**
1. The simulation begins with the generator connected to the total system.
2. The generator is islanded by onshore island breakers.
3. The frequency may transiently above 5.2Hz in responding to the disconnection of demand provided the duration of any excursion beyond 5.2Hz is less than the high frequency protection trip time for the generator.
(i) a sufficiently large reduction in the measured System Frequency ramped over 10 seconds to cause an increase in Active Power output to the Maximum Capacity followed by

(ii) 60 seconds of steady state with the measured System Frequency depressed to the same level as in ECP.A.3.6.8.1 (i) as illustrated in Figure ECP.A.3.6.1 below.

(iii) then increase of the measured System Frequency ramped over 10 seconds to cause a reduction in Active Power output back to the original Active Power level followed by at least 60 seconds of steady output.

![Figure ECP.A.3.6.1](image)

ECP.A.3.7 Voltage and Frequency Controller Model Verification and Validation

ECP.A.3.7.1 For Type C and Type D Synchronous Power Generating Modules, HVDC Equipment, OTSDUW Plant and Apparatus or Power Park Modules, the Generator (including those undertaking OTSDUW) or HVDC System Owner shall provide simulation studies to verify that the proposed controller models supplied to The Company under the Planning Code are fit for purpose. These simulation study results shall be provided in the timescales stated in the Planning Code.

ECP.A.3.7.2 To demonstrate the Frequency control or governor/load controller/plant model the Generator or HVDC System Owner shall submit a simulation study representing the response of the Synchronous Power Generating Module, HVDC Equipment or Power Park Module operating at 80% of Maximum Capacity. The simulation study event shall be equivalent to:

(i) a ramped reduction in the measured System Frequency of 0.5Hz in 10 seconds followed by

(ii) 20 seconds of steady state with the measured System Frequency depressed by 0.5Hz followed by

(iii) a ramped increase in measured System Frequency of 0.3Hz over 30 seconds followed by

(iv) 60 seconds of steady state with the measured System Frequency depressed by 0.2Hz as illustrated in Figure ECP.A.3.7.2 below.
The simulation study shall show Active Power output (MW) and the equivalent of Frequency injected.

**ECP.A.3.7.3** To demonstrate the Excitation System model the Generator shall submit simulation studies representing the response of the Synchronous Power Generating Module as follows:

(i) operating open circuit at rated terminal voltage and subjected to a 10% step increase in terminal voltage reference from 90% to 100%.

(ii) operating at Rated MW, nominal terminal voltage and unity Power Factor subjected to a 2% step increase in the voltage reference. Where a Power System Stabiliser is included within the Excitation System this shall be in service.

The simulation study shall show the Synchronous Power Generating Module terminal voltage, field voltage, Active Power, Reactive Power and Power System Stabiliser output signal as appropriate.

**ECP.A.3.7.4** To demonstrate the Voltage Controller model the Generator (including those undertaking OTSDUW) or HVDC System Owner shall submit a simulation study representing the response of the HVDC Equipment, OTSDUW Plant and Apparatus or Power Park Module operating at Rated MW and unity Power Factor at the connection point to a 2% step increase in the voltage reference. The simulation study shall show the terminal voltage, Active Power, Reactive Power and Power System Stabiliser output signal as appropriate.

**ECP.A.3.7.5** To validate that the excitation and voltage control models submitted under the Planning Code are a reasonable representation of the dynamic behaviour of the Synchronous Power Generating Module, OTSDUW Plant and Apparatus, HVDC Equipment or Power Park Module as built, the Generator or HVDC System Owner shall repeat the simulation studies outlined above but using the operating conditions of the equivalent tests. The simulation study results shall be displayed overlaid on the actual test results.

**ECP.A.3.7.6** For Type C and Type D Synchronous Power Generating Modules or HVDC Equipment to validate that the governor/load controller/plant or Frequency control models submitted under the Planning Code is a reasonable representation of the dynamic behaviour of the Synchronous Power Generating Module or HVDC Equipment Station as built, the Generator or HVDC System Owner shall repeat the simulation studies outlined above but using the operating conditions of the equivalent tests. The simulation study results shall be displayed overlaid on the actual test results.
ECP.A.3.8  Sub-synchronous Resonance control and Power Oscillation Damping control for HVDC System.

ECP.A.3.8.1  To demonstrate the compliance of the sub-synchronous control capability with ECC.6.3.17.1) and the terms of the Bilateral Agreement, the HVDC System Owner shall submit a simulation study report.

ECP.A.3.8.2  Where power oscillation damping control function is specified on a HVDC Equipment the HVDC System Owner shall submit a simulation study report to demonstrate the compliance with ECC.6.3.17.2 and the terms of the Bilateral Agreement.

ECP.A.3.8.3  The simulation studies should utilise the HVDC Equipment control system models including the settings as required under the Planning Code (PC.A.5.3.2). The network conditions for the above simulation studies should be discussed with The Company prior to commencing any simulation studies.

ECP.A.3.9  Grid Forming Plant verification and validation

ECP.A.3.9.1  This section applies to Users and Non-CUSC Parties who own and operate GBGF-I Plant to demonstrate the ability of their Grid Forming Plant to satisfy the requirements of ECC.6.3.19. For the avoidance of doubt these requirements are not necessary from owner and operators of GBGF-S Plant.

ECP.A.3.9.2  For initial approval Users and Non-CUSC Parties are required to submit the following data of their Grid Forming Plant to The Company:
   a) The representation of their Grid Forming Plant in a format either the same as Figure PC.A.5.8.1 of PC.A.5.8.1 or in an equivalent format.
   b) The data associated with their Grid Forming Plant as required in PC.A.5.8.1
   c) A linearised model and parameters of the Grid Forming Plant in the frequency domain in the same format as required in PC.A.5.8.1 or equivalent.
   d) A Network Frequency Perturbation Plot with a Nichols Chart demonstrating the equivalent Damping Factor.
   e) For the items a) to d) the User or Non-CUSC Party can submit the data in any equivalent format as agreed with The Company.

ECP.A.3.9.3  For GBGF-I, the User or Non-CUSC Party may be required to supply other versions of the Network Frequency Perturbation Plot for different input and output signals as defined by The Company.

ECP.A.3.9.4  For final approval, Users and Non-CUSC Parties are required to demonstrate that the GBGF-I model is capable of supplying Active ROCOF Response Power, and Active Phase Jump Power, and submit a full 3 phase simulation study in the time domain representing the response of the Grid Forming Plant over a range of operating conditions. The simulation study shall comprise of the following stages.

   i) A simulation study to the equivalent shown in Figure ECP.A.3.9.4.
ii) The first simulation test is to demonstrate that the GBGF-I model is capable of supplying Active ROCOF Response Power to the Total System as a result of a System Frequency change. In this simulation, with the Grid Forming Plant initially running at Registered Capacity or Maximum Capacity, the Grid System Frequency is increased from 50Hz to 51Hz at a rate of 1Hz/s with measurements of the Grid Forming Plant’s Active ROCOF Response Power, System Frequency and time in (ms). The simulation is required to assess correct operation of the Grid Forming Plant without saturating. Repeat for 50Hz to 49Hz at 1Hz/s.

iii) The second simulation test is to demonstrate the GBGF-I’s ability to supply Active ROCOF Response Power and assess its withstand capability under extreme System Frequencies. The Grid System Frequency is increased from 50Hz to 52Hz at a rate of 1Hz/s with measurements of the Active ROCOF Response Power, System Frequency and time in (ms). This is repeated when the Grid System Frequency is increased from 50Hz to 52Hz at a rate of 2 Hz/s with measurements of the Active ROCOF Response Power, System Frequency and time in (ms). Repeat for 50Hz to 48 Hz at 1 Hz/s and 50Hz to 48 Hz at 2 Hz/s.

iv) The third simulation is to demonstrate the Grid Forming Plant’s ability to supply Active ROCOF Response Power over the full System Frequency range.

(a) With the System Frequency set to 50Hz, the Grid Forming Plant should be initially running at 75% Maximum Capacity or 75% Registered Capacity, zero MVAr output and both Limited Frequency Sensitive Mode and Frequency Sensitive Mode disabled.

(b) The System Frequency is then increased from 50Hz to 52Hz at a rate of 1Hz/s over a 2 second period. Allow conditions to stabilise for 5 seconds and then decrease the System Frequency from 52Hz to 47Hz at a rate of 1Hz/s over a 5 second period. Allow conditions to stabilise.

(c) Record results of phase based Active ROCOF Response Power, Reactive Power, voltage and System Frequency.

(d) The simulation now needs to be re-run in the opposite direction. The same initial conditions should be applied as per ECP.A.3.9.2iv) (a).

(e) The System Frequency is then decreased from 50Hz to 47Hz at a rate of 1Hz/s over a 3 second period. Allow conditions to stabilise for 5 seconds and then increase the System Frequency from 47Hz to 52Hz at a rate of 1Hz/s over a 5 second period. Allow conditions to stabilise.
(f) Record results of Active ROCOF Response Power, Reactive Power, voltage and System Frequency.

(g) The simulation is required to ensure the Grid Forming Plant can deliver Active ROCOF Response Power without going into saturation and that a behaviour that is equivalent to pole slipping does not occur.

v) The fourth simulation is to demonstrate the Grid Forming Plant's ability to supply Active Phase Jump Power under normal operation.

(a) With the System Frequency set to 50Hz, the Grid Forming Plant should initially be running at Maximum Capacity or Registered Capacity or a suitable loading point to demonstrate Grid Forming Capability as agreed with The Company, zero MVAr output and all control actions (e.g. Limited Frequency Sensitive Mode, Frequency Sensitive Mode and voltage control) disabled.

(b) Apply a positive phase jump of the Phase Jump Angle Limit value at the Grid Entry Point or User System Entry Point.

(c) Record traces of Active Power, Reactive Power, voltage, current and System Frequency for a period of 10 seconds after the step change in phase has been applied. Repeat with a negative phase jump.

vi) The fifth simulation is to demonstrate the Grid Forming Plant's ability to supply Active Phase Jump Power under extreme conditions.

(a) With the System Frequency set to 50Hz, the Grid Forming Plant should be initially running at its Minimum Stable Operating Level or Minimum Stable Generation, zero MVAr output and all control actions (e.g. Limited Frequency Sensitive Mode, Frequency Sensitive Mode and voltage control) disabled.

(b) Apply a phase jump equivalent to the positive Phase Jump Angle Withstand value at the Grid.

(c) Record traces of Active Power, Reactive Power, voltage, current and System Frequency for a period of 10 seconds after the step change in phase has been applied. Repeat with a negative phase jump.

(d) Repeat steps (a), (b) and (c) of ECP.A.3.9.4(vi) but on this occasion apply a phase jump equivalent to the positive Phase Jump Angle Limit at the Grid.

vii) The sixth simulation is to demonstrate the Grid Forming Plant's ability to supply Fault Ride Through and GBGF Fast Fault Current Injection during a faulted condition.

(a) With the System Frequency set to 50Hz, the Grid Forming Plant should be initially running at its Maximum Capacity or Registered Capacity, zero MVAr output and all control actions (e.g., Limited Frequency Sensitive Mode, Frequency Sensitive Mode, GBGF Fast Fault Current Injection, Fault Ride Through and voltage control other than current limiters) disabled.

(b) Apply a solid three phase short circuit fault at the Grid Entry Point or User System Entry Point for 140ms.

(c) Record traces of Active Power, Reactive Power, voltage, current and System Frequency for a period of 10 seconds after the fault
has been applied. The GBGF-I’s current limit should be observed to operate.

(d) Repeat steps (a) to (c) but on this occasion with **Fault Ride Through**, **GBGF Fast Fault Current Injection**, **Limited Frequency Sensitive Mode** and voltage control switched into service.

(e) Record traces of **Active Power**, **Reactive Power**, voltage, current and **System Frequency** for a period of 10 seconds after the fault has been applied and confirm correct operation.

**ECP.A.3.9.5**

To demonstrate the GBGF-I model is capable of supplying **Active ROCOF Response Power** and **Active Phase Jump Power**, under extreme conditions the **Grid Forming Plant Owner** shall submit a simulation study representing the response of the **Grid Forming Plant**. To demonstrate the performance of the **Grid Forming Plant** under these conditions, the simulation study shall represent the following scenario.

i) The **User** or **Non-CUSC Party** in respect of GBGF-I should supply a simulation study to **The Company** equivalent to Figure ECP.A.3.9.5.

![Variable Frequency Grid Diagram](image)

Figure ECP.A.3.9.5

ii) In this simulation (as shown in Figure ECP.A.3.9.5) the parameters of the variable frequency Grid shall be supplied by **The Company**. The Load Y is also defined by **The Company**.

iii) With the system running in steady state the GBGF-I and the variable frequency AC Grid should each be running at load Y/2 with the **System Frequency** of the test network being 50Hz. All control actions (e.g., **Limited Frequency Sensitive Mode**, **Frequency Sensitive Mode** and voltage control) should be disabled.

iv) With the system in steady state, apply a solid (zero impedance) three phase short circuit fault at point A of Figure ECP.A.3.9.3 and then open circuit breaker B, 140ms after the fault has been applied.
v) Record traces of **Active Power**, **Reactive Power**, voltage and **System Frequency** and record for a period of time after fault inception after allowing conditions to stabilise.

**ECP.A.3.9.6**

To demonstrate the **Grid Forming Plant** model is capable of contributing to **Active Damping Power**, the GBGF-I owner is required to supply a simulation study by injecting a **Test Signal** in the time domain into the model of the GBGF-I.

The GBGF-I model should take the equivalent form shown in either Figure ECP.A.3.9.6(a) or Figure ECP.A.3.9.6(b) as applicable. Each **User** or **Non-CUSC Party** can use their own design, that may be very different to Figures ECP.A.3.9.6(a) or ECP.A.3.9.6 (b) but should contain all relevant functions. In either case the following tests should be completed, and results supplied to verify the following criteria:

**Typical simulation model 1**

![Diagram](image1)

**Figure ECP.A.3.9.6(a)**

**Typical simulation model 2**

![Diagram](image2)

**Figure ECP.A.3.9.6(b)**

i) Demonstration of **Damping** by injecting a **Test Signal** in the time domain at the **Grid Oscillation Value** and frequency into the model of the GBGF-I. An acceptable performance will be judged when the result matches the **NFP Plot** declared by the **Grid Forming Plant Owner** as submitted in PC.A.5.8.1(i).

ii) Test i) is repeated with variations in the frequency of the **Test Signal**. An acceptable performance will be judged when the result matches the **NFP Plot** declared by the **Grid Forming Plant Owner** as submitted in PC.A.5.8.1(i).

iii) Demonstration of phase based **Active Control Output Power** (or **Pc**) by injecting a **Test Signal** into the **Grid Forming Plant** controller to demonstrate that the **Active Control Based Power** output is supplied below the 5Hz bandwidth limit. An acceptable performance will be judged where the overshoot and decay matches the **Damping Factor** declared by the **Grid Forming Plant Owner** as submitted in PC.A.5.8.1 in addition to assessment against the requirements of CC.A.6.2.6.1 or ECC.A.6.2.6.1 or CC.A.7.2.2.5 or ECC.A.7.2.5.2 as applicable.
## APPENDIX 4

### ONSITE SIGNAL PROVISION FOR WITNESSING TESTS

**ECP.A.4.1**

During any tests witnessed on-site by The Company, the following signals shall be provided to The Company by the Generator undertaking OTSDUW or HVDC System Owner in accordance with ECC.6.6.3.

**ECP.A.4.2**

**Synchronous Power Generating Modules**

<table>
<thead>
<tr>
<th>ECP.A.4.2(a) All Tests</th>
<th>- MW - Active Power at Synchronous Generating Unit terminals</th>
</tr>
</thead>
</table>
| ECP.A.4.2(b) Reactive & Excitation System | \- MVar - Reactive Power at terminals  
\- Vt - Synchronous Generating Unit terminal voltage  
\- Efd- Synchronous Generating Unit field voltage and/or main exciter field voltage  
\- Ifd – Synchronous Generating Unit Field current (where possible)  
\- Power System Stabiliser output, where applicable.  
\- Noise – Injected noise signal (where applicable and possible) |
| ECP.A.4.2(c) Governor System & Frequency Response | \- Fsyst - System Frequency  
\- Finj - Injected Speed Setpoint  
\- 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 \( \geq 1 \)Hz: | \- 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 |
| ECP.A.4.2(d) Compliance with ECC.6.3.3 | \- Fsyst - System Frequency  
\- Finj - Injected Speed Setpoint  
\- Appropriate control system parameters as agreed with The Company (See ECP.A.5.9) |
| ECP.A.4.2(e) Real Time on site or Down-loadable | \- MW - Synchronous Power Generating Module Active Power at the Grid Entry Point or (User System Entry Point if Embedded).  
\- MVar - Synchronous Power Generating Module Reactive Power at the Grid Entry Point or (User System Entry Point if Embedded). |
ECP.A.4.3  
Power Park Modules, OTSDUA and HVDC Equipment

<table>
<thead>
<tr>
<th>ECP.A.4.3.1(a)</th>
<th>Each Power Park Module and HVDC Equipment at Grid Entry Point or User System Entry Point</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPC.A.4.3.1(a)</td>
<td>Real Time on site.</td>
</tr>
<tr>
<td></td>
<td>• Total <strong>Active Power</strong> (MW)</td>
</tr>
<tr>
<td></td>
<td>• Total <strong>Reactive Power</strong> (MVAr)</td>
</tr>
<tr>
<td></td>
<td>• Line-line Voltage (kV)</td>
</tr>
<tr>
<td></td>
<td>• <strong>System Frequency</strong> (Hz)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>ECP.A.4.3.1(b)</th>
<th>Real Time on site or Down-loadable</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPC.A.4.3.1(b)</td>
<td>• Injected frequency signal (Hz) or test logic signal (Boolean) when appropriate</td>
</tr>
<tr>
<td></td>
<td>• Injected voltage signal (per unit voltage) or test logic signal (Boolean) when appropriate</td>
</tr>
<tr>
<td></td>
<td>• In the case of an <strong>Onshore Power Park Module</strong> the Onshore Power Park Module site voltage (MV) (kV)</td>
</tr>
<tr>
<td></td>
<td>• <strong>Power System Stabiliser</strong> output, where appropriate</td>
</tr>
<tr>
<td></td>
<td>• In the case of a <strong>Power Park Module</strong> or <strong>HVDC Equipment</strong> where the Reactive Power is provided by more than one Reactive Power source, the individual Reactive Power contributions from each source, as agreed with The Company.</td>
</tr>
<tr>
<td></td>
<td>• In the case of <strong>HVDC Equipment</strong> appropriate control system parameters as agreed with The Company (See ECP.A.7)</td>
</tr>
<tr>
<td></td>
<td>• In the case of an <strong>Offshore Power Park Module</strong> the Total <strong>Active Power</strong> (MW) and the Total <strong>Reactive Power</strong> (MVAr) at the offshore Grid Entry Point</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>ECP.A.4.3.1(c)</th>
<th>Real Time on site or Down-loadable</th>
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</thead>
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<td>EPC.A.4.3.1(c)</td>
<td>• Available power for <strong>Power Park Module</strong> (MW)</td>
</tr>
<tr>
<td></td>
<td>• Power source speed for <strong>Power Park Module</strong> (e.g. wind speed) (m/s) when appropriate</td>
</tr>
<tr>
<td></td>
<td>• Power source direction for <strong>Power Park Module</strong> (degrees) when appropriate</td>
</tr>
</tbody>
</table>

ECP.A.4.3.2  The Company accept that the signals specified in ECP.A.4.3.1(c) may have lower effective sample rates than those required in ECC.6.6.3 although any signals supplied for connection to The Company's recording equipment which do not meet at least the sample rates detailed in ECC.6.6.3 should have the actual sample rates indicated to The Company before testing commences.

ECP.A.4.3.3  For all The Company witnessed testing either;

(i)  the Generator or HVDC System Owner shall provide to The Company all signals outlined in ECP.A.4.3.1 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 ECC.6.6.3.2; or

(ii) in the case of Onshore Power Park Modules, the Generator or HVDC System Owner shall provide signals ECP.A.4.3.1(a) direct from one or more transducer(s) connected to current and voltage transformers for monitoring in real time on site; or,
In the case of Offshore Power Park Modules and OTSDUA signals ECP.A.4.3.1(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.

ECP.A.4.3.4 Options ECP.A.4.3.3 (ii) and (iii) will only be available on condition that;

(a) all signals outlined in ECP.A.4.3.1 are recorded and made available to The Company by the Generator or HVDC System Owner from the Power Park Module or OTSDUA or HVDC Equipment control systems as a download once the testing has been completed; and

(b) the full test results are provided by the Generator HVDC System 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 ECC.6.6.3.3 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.

ECP.A.4.3.5 In the case of where transducers connected to current and voltage transformers are installed (ECP.A.4.3.3(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%.

ECP.A.4.3.6 In the case of a GBGF-I system, the following signals shall be supplied to The Company by the Grid Forming Plant Owner in accordance with ECC.6.6.3. For the avoidance of doubt, User’s and Non-CUSC Parties will also be required to undertake the necessary testing of their Plant in accordance with the requirements of ECC.A.4 and OC5 as applicable.

<table>
<thead>
<tr>
<th>ECP.A.4.3.6(a) Real Time Downloadable</th>
<th>Each Grid Forming Plant at the Grid Entry Point or User System Entry Point</th>
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<tbody>
<tr>
<td>Signals required shall be agreed with The Company in accordance with ECC.6.6.3.2(iv) and ECC.6.6.3.2(v)</td>
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</tr>
</tbody>
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ECP.A.4.3.7 Testing not witnessed by The Company on-site

ECP.A.4.3.7.1.1 Where The Company has decided not to witness testing on-site, the results shall be submitted to The Company in spreadsheet format with the signal data in columns arranged as follows. Signal data denoted by "#" is not essential but if not provided the column should remain in place but without values entered. Where two signal names are given in a column these are alternatives related to the type of plant under test.

ECP.A.4.3.7.1.2 Where The Company has requested addition signals to be recorded prior to the testing these signals shall be placed in columns to the right of the spreadsheet.

### Onshore Synchronous Generating Unit Excitation System and Reactive Capability

<table>
<thead>
<tr>
<th>Col 1</th>
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<th>Col 4</th>
<th>Col 5</th>
<th>Col 6</th>
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<td>Reactive</td>
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<td>Freq</td>
<td>Logic /</td>
<td>Field</td>
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<td>Voltage</td>
<td>/Frequency</td>
<td>Injection</td>
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<td>Voltage</td>
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Col 9 to Col 16

# Columns may be left blank but the column must still be included in the files

### Onshore Synchronous Generating Unit Frequency Response and ECC.6.3.3

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Col 9 to Col 16

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### Onshore Power Park Modules Voltage Control & Reactive Capability

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<td>Reactive</td>
<td>Connectio</td>
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<td>Freq</td>
<td>Logic /</td>
<td>Statcom</td>
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<td>/Frequenc y</td>
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<td>Wind Direction</td>
<td>Voltage Setpoint</td>
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**ECP.A.4.3.7.3.2** Offshore Power Park Modules Voltage Control & Reactive Capability

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<tbody>
<tr>
<td>Time</td>
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<td>Onshore Interface Point Reactive Power</td>
<td>Onshore Interface Point Voltage</td>
<td>Speed /Frequency #</td>
<td>Freq Injection #</td>
<td>Logic / Test Start #</td>
<td>Statcom or Windfarm Reactive Power #</td>
</tr>
<tr>
<td>Col 9</td>
<td>Col 10</td>
<td>Col 11</td>
<td>Col 12</td>
<td>Col 13</td>
<td>Col 14</td>
<td>Col 15</td>
<td>Col 16</td>
</tr>
<tr>
<td>Power Available</td>
<td>Wind Speed m/s</td>
<td>Wind Direction</td>
<td>Voltage Setpoint</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

# Columns may be left blank but the column must still be included in the files

**ECP.A.4.3.7.3.3** Power Park Module Frequency Control

<table>
<thead>
<tr>
<th>Col 1</th>
<th>Col 2</th>
<th>Col 3</th>
<th>Col 4</th>
<th>Col 5</th>
<th>Col 6</th>
<th>Col 7</th>
<th>Col 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Time</td>
<td>GEP Active Power</td>
<td>GEP Reactive Power #</td>
<td>GEP Connectio n Voltage #</td>
<td>Speed /Frequenc y</td>
<td>Freq Injectio n</td>
<td>Logi c / Test Start</td>
<td>Statcom or Windfar m Reactive Power #</td>
</tr>
<tr>
<td>Col 9</td>
<td>Col 10</td>
<td>Col 11</td>
<td>Col 12</td>
<td>Col 13</td>
<td>Col 14</td>
<td>Col 15</td>
<td>Col 16</td>
</tr>
<tr>
<td>Power Available</td>
<td>Wind Speed m/s</td>
<td>Wind Direction</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

# Columns may be left blank but must still be included in the files

**ECP.A.4.3.8.1** Where test results are completed without the presence of The Company but are relied upon as evidence of the compliance they should be accompanied by a logsheet. This sheet should be legible, in English and detail the items as indicated below:

- Time and Date of test;
Name of **Power Station** and **Power Generating Module** if applicable;
Name of Test engineer(s) and company name;
Name of **Users** representative(s) and company name;
Type of testing being undertake eg Voltage Control;
Ambient conditions eg. temperature, pressure, wind speed, wind direction; and
Controller settings, eg voltage slope, frequency droop, voltage setpoint, UEL & OEL settings

ECP.A.4.3.8.2 For each test the following items should be recorded as relevant to the type of test being undertaken. Where there is uncertainty on the information to be recorded this should be discussed with **The Company** in advance of the test.

ECP.A.4.3.8.2.1 Voltage Control Tests

Start time of each test step;
**Active Power**;
**Reactive Power**;
Connection voltage;
Voltage Control Setpoint, if applicable or changed;
Voltage Control Slope, if applicable or changed;
Terminal Voltage if applicable;
Generator transformer tap position or grid transformer tap position, as applicable;
Number of **Power Park Units** in service in each **Power Park Module**, if applicable; and
For offshore connections **Offshore Grid Entry Point** voltage.

ECP.A.4.3.8.2.2 Reactive Power Capability Tests

Start time of test;
**Active Power**;
**Reactive Power**;
Connection Voltage;
Terminal Voltage if applicable;
**Generating Unit** transformer tap position or grid transformer tap position as applicable;
Number of **Power Park Units** in service in each **Power Park Module**, if applicable; and
For offshore connections **Offshore Grid Entry Point** voltage.

ECP.A.4.3.8.2.3 Frequency Response Capability Tests

Start time of test;
**Active Power**;
System Frequency:
For CCGT Modules, Active Power for the individual units (GT & ST);
For boiler plant, HP steam pressure;
Droop setting of controller if applicable;
Number of Power Park Units in service in each Power Park Module, if applicable; and
For offshore connections Offshore Grid Entry Point Active Power for each Power Park Module.

ECP.A.4.3.8.3 Material changes during the test period should be recorded e.g. Generating Units tripping / starting, changes to tapchange positions.
APPENDIX 5

COMPLIANCE TESTING OF SYNCHRONOUS POWER GENERATING MODULES

ECP.A.5.1 SCOPE

ECP.A.5.1.1 This Appendix sets out the tests contained therein to demonstrate compliance with the relevant clauses of the European Connection Conditions of the Grid Code. This Appendix shall be read in conjunction with the ECP with regard to the submission of the reports to The Company.

ECP.A.5.1.2 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 Synchronous Power Generating Module following successful completion of the first Synchronous Power Generating Module tests in the case of a Power Station comprised of two or more Synchronous Power Generating Modules which The Company reasonably considers to be identical.

If:

(a) the tests performed pursuant to ECP.A.5.1.2(iii) in respect of subsequent Synchronous Power Generating Modules do not replicate the full tests for the first Synchronous Power Generating Module, or

(b) any of the tests performed pursuant to ECP.A.5.1.2(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.

ECP.A.5.1.3 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 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 ECP.A.6.1.5.

ECP.A.5.1.4 The Generator shall submit a schedule of tests to The Company in accordance with CP.4.3.1.

ECP.A.5.1.5 Prior to the testing of a Synchronous Power Generating Module the
Generator shall complete the Integral Equipment Test procedure in accordance with OC.7.5.

ECP.A.5.1.6 Full Synchronous Power Generating Module testing as required by CP.7.2 is to be completed as defined in ECP.A.5.2 through to ECP.A.5.9.

ECP.A.5.1.7 The Company will permit relaxation from the requirement ECP.A.5.2 to ECP.A.5.9 where an Equipment Certificate for the Synchronous Power Generating Module has been provided which details the characteristics from tests on a representative machine with the same equipment and settings and the performance of the Synchronous Power Generating Module can, in The Company’s opinion, reasonably represent that of the installed Synchronous Power Generating Module at that site. For Type B, Type C and Type D Power Generating Modules the relevant Equipment Certificate must be supplied in the Power Generating Module Document or Users Data File structure as applicable.

ECP.A.5.1.8 In the case of a co-located site, for example Electricity Storage Modules or Grid Forming Plant connected within a new or existing Power Station, The Company will accept test results to demonstrate compliance at the Grid Entry Point or User System Entry Point (if Embedded) through a combination of the capabilities of the Power Generating Modules (which could include Grid Forming Plant) and Electricity Storage Modules or Electricity Storage Modules (which could include a Grid Forming Plant) and Generating Units or Power Park Modules. Generators should however be aware that for the purposes of testing, full Grid Code compliance should be demonstrated when, for example, the Electricity Storage Module or Grid Forming Plant is out of service and the remaining Power Generating Module is in service or the Electricity Storage Module or Grid Forming Plant is in service and the Power Generating Module is out of service. In the case of a Synchronous Electricity Storage Module, The Company would expect the full set of tests to be completed as detailed in ECP.A.5.2 to ECP.A.5.9.

ECP.A.5.2 Excitation System Open Circuit Step Response Tests

ECP.A.5.2.1 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 Synchronous Power Generating Module terminal voltage, with the Synchronous Power Generating Module on open circuit and at rated speed.

ECP.A.5.2.2 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 - Synchronous Generating Unit terminal voltage
Efd - Synchronous Generating Unit field voltage or main exciter field voltage
Ifd - Synchronous Generating Unit field current (where possible)
Step injection signal

ECP.A.5.2.3 Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

ECP.A.5.3 Open & Short Circuit Saturation Characteristics

ECP.A.5.3.1 The test shall normally be carried out prior to synchronisation in accordance with ECP.6.2.4 or ECP.6.3.4 Equipment Certificates or Manufacturer’s Test Certificates may be used where appropriate may be used if agreed by The Company.
ECP.A.5.3.2 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.

ECP.A.5.3.3 Results shall be legible, identifiable by labelling, and shall have appropriate scaling.

ECP.A.5.4 **Excitation System On-Load Tests**

ECP.A.5.4.1 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.

ECP.A.5.4.2 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 Synchronous 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 Setpoint with the Synchronous 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 Synchronous 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 Synchronous Generating Unit is selected to Frequency Sensitive Mode.

(vi) If the Synchronous Power Generating Module is of the Pumped 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. In the case of a Synchronous Electricity Storage Module the tests shall be carried out with and without the PSS in both importing and exporting modes of operation.

(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 Synchronous Power Generating 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.
ECP.A.5.4.3 The following typical procedure is provided to assist Generators in drawing up their own site specific procedures for The Company witnessed PSS Tests.

<table>
<thead>
<tr>
<th>Test</th>
<th>Injection</th>
<th>Notes</th>
</tr>
</thead>
</table>
| 1    | • Record steady state for 10 seconds  
      | • Inject +1% step to AVR voltage setpoint and hold for at least 10 seconds until stabilised  
      | • Remove step returning AVR voltage setpoint to nominal and hold for at least 10 seconds |
| 2    | • Record steady state for 10 seconds  
      | • Inject +2% step to AVR voltage setpoint and hold for at least 10 seconds until stabilised  
      | • Remove step returning AVR voltage setpoint to nominal and hold for at least 10 seconds |
| 3    | • Inject band limited (0.2-3Hz) random noise signal into voltage setpoint and measure frequency spectrum of Real Power.  
      | • Remove noise injection. |
| 4    | • Record steady state for 10 seconds  
      | • Inject +1% step to AVR voltage setpoint and hold for at least 10 seconds until stabilised  
      | • Remove step returning AVR voltage setpoint to nominal and hold for at least 10 seconds |
| 5    | • Record steady state for 10 seconds  
      | • Inject +2% step to AVR Voltage Setpoint and hold for at least 10 seconds until stabilised  
      | • Remove step returning AVR Voltage Setpoint to nominal and hold for at least 10 seconds |
| 6    | • Increase PSS gain at 30second 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 setpoint 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 |

ECP.A.5.5 Under-excitation Limiter Performance Test

ECP.A.5.5.1 Initially the performance of the Under-excitation Limiter should be checked by moving the limit line close to the operating point of the Synchronous Generating Unit when operating close to unity Power Factor. The operating point of the Synchronous Generating Unit is then stepped into the limit by applying a 2% decrease in Automatic Voltage Regulator Setpoint voltage.

ECP.A.5.5.2 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 Setpoint voltage when the Synchronous Generating Unit is operating just off the limit line, at the designed setting as indicated on the Performance Chart [P-Q Capability Diagram] submitted to The Company under OC2.

ECP.A.5.5.3 Where possible the Under-excitation Limiter should also be tested by operating the tap-changer when the Synchronous Generating Unit is
operating just off the limit line, as set up.

ECP.A.5.5.4 The Under-excitation Limiter will normally be tested at low active power output and at maximum Active Power output.

ECP.A.5.5.5 The following typical procedure is provided to assist Generators in drawing up their own site specific procedures for The Company witnessed Under-excitation Limiter Tests.

<table>
<thead>
<tr>
<th>Test</th>
<th>Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Synchronous Generating Unit</strong> running at Maximum Capacity and unity Power Factor. Under-excitation limit temporarily moved close to the operating point of the Synchronous Generating Unit.</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>• PSS on. • Inject -2% voltage step into AVR voltage setpoint and hold at least for 10 seconds until stabilised • Remove step returning AVR voltage setpoint to nominal and hold for at least 10 seconds</td>
<td>Under-excitation limit moved to normal position. <strong>Synchronous Generating Unit</strong> running at Maximum Capacity and at leading Reactive Power close to Under-excitation limit.</td>
</tr>
<tr>
<td>2</td>
<td>• PSS on. • Inject -2% voltage step into AVR voltage setpoint and hold at least for 10 seconds until stabilised • Remove step returning AVR voltage setpoint to nominal and hold for at least 10 seconds</td>
<td></td>
</tr>
</tbody>
</table>

**ECP.A.5.6 Over-excitation Limiter Performance Test**

ECP.A.5.6.1 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 Setpoint Voltage that results in operation of the Over-excitation Limiter. Prior to application of the step the Synchronous Generating Unit shall be generating Maximum Capacity 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 Synchronous Power Generating Module. The step shall be removed immediately on completion of the test.

ECP.A.5.6.2 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.

ECP.A.5.6.3 The following typical procedure is provided to assist Generators in drawing up their own site specific procedures for The Company witnessed Under-excitation Limiter Tests.

<table>
<thead>
<tr>
<th>Test</th>
<th>Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><strong>Synchronous Generating Unit</strong> running at Maximum Capacity and maximum lagging Reactive Power</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Over-excitation Limit temporarily set close to this operating point. PSS on.</td>
<td></td>
</tr>
<tr>
<td>1</td>
<td>• Inject positive voltage step into AVR voltage setpoint and</td>
<td></td>
</tr>
</tbody>
</table>
### ECP.A.5.7 Reactive Capability

#### ECP.A.5.7.1

The **Reactive Power** capability on each **Synchronous Power Generating Module** will normally be demonstrated by:

- **(a)** operation of the **Synchronous Power Generating Module** at maximum lagging **Reactive Power** and Maximum Capacity for 1 hour.

- **(b)** operation of the **Synchronous Power Generating Module** at maximum leading **Reactive Power** and Maximum Capacity for 1 hour.

- **(c)** operation of the **Synchronous Power Generating Module** at maximum lagging **Reactive Power** and Minimum Stable Operating Level for 1 hour.

- **(d)** operation of the **Synchronous Power Generating Module** at maximum leading **Reactive Power** and Minimum Stable Operating Level for 1 hour.

- **(e)** operation of the **Synchronous Power Generating Module** at maximum lagging **Reactive Power** and a power output between Maximum Capacity and Minimum Stable Operating Level.

- **(f)** operation of the **Synchronous Power Generating Module** at maximum leading **Reactive Power** and a power output between Maximum Capacity and Minimum Stable Operating Level.

In the case of a **Synchronous Electricity Storage Module**, The Company shall have discretion to reduce the durations of the tests set out in ECP.A.5.7.1 (a) – (f), depending upon the capacity of the energy store.

#### ECP.A.5.7.2

In the case of an **Embedded Synchronous Power Generating Module** where distribution network considerations restrict the **Synchronous Power Generating Module Reactive Power** output, The Company will only require demonstration within the acceptable limits of the **Network Operator’s System**.

#### ECP.A.5.7.3

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 Company control centre and by the Generator.

#### ECP.A.5.7.4

Where the Generator is recording the voltage, **Active Power** and **Reactive Power** at the HV connection point the voltage for these tests **Active Power** and **Reactive Power** at the **Synchronous Power Generating Module** terminals may also be included. The results shall be supplied in an electronic spreadsheet format. Where applicable the **Synchronous Power Generating Module** transformer tapchanger position should be noted throughout the test period.

#### ECP.A.5.8 Governor and Load Controller Response Performance
ECP.A.5.8.1 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 setpoints. For CCGT modules, simultaneous injection into all gas turbines, steam turbine governors and module controllers is required.

ECP.A.5.8.2 Prior to witnessing the governor tests set out in ECP.A.5.8.6, The Company requires the Generator to conduct the preliminary tests detailed in ECP.A.5.8.4 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.

ECP.A.5.8.3 Where a CCGT module or Synchronous Power Generating Module 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 ECP.A.5.8.6 for demonstrating performance on the alternative fuel. This includes the case where a main fuel is supplemented by bio-fuel.

Preliminary Governor Frequency Response Testing

ECP.A.5.8.4 Prior to conducting the full set of tests as per ECP.A.5.8.6, 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.

<table>
<thead>
<tr>
<th>Test No (Figure1)</th>
<th>Frequency Injection</th>
<th>Notes</th>
</tr>
</thead>
</table>
| 8                | • 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 as a ramp over 10 seconds |
| 13               | • Inject -0.5Hz frequency fall over 10 sec  
• Hold until conditions stabilise  
• Remove the injected signal as a ramp over 10 seconds |
| 14               | • Inject +0.5Hz frequency rise over 10 sec  
• Hold until conditions stabilise  
• Remove the injected signal as a ramp over 10 seconds |
| H                | • Inject -0.5Hz frequency fall as a stepchange  
• Hold until conditions stabilise  
• Remove the injected signal as a stepchange |
| I                | • Inject +0.5Hz frequency rise as a stepchange  
• Hold until conditions stabilise  
• Remove the injected signal as a stepchange |

ECP.A.5.8.5 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
ECP.A.5.8.6 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.

<table>
<thead>
<tr>
<th>Module Load Point 6</th>
<th>Module Load Point 5</th>
<th>Module Load Point 4</th>
<th>Module Load Point 3</th>
<th>Module Load Point 2</th>
<th>Module Load Point 1</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Maximum Export Limit)</td>
<td>100% MEL</td>
<td>95% MEL</td>
<td>80% MEL</td>
<td>70% MEL</td>
<td>MRL+10% or MSOL</td>
</tr>
<tr>
<td>(Mid-point of Operating Range)</td>
<td>95% MEL</td>
<td>80% MEL</td>
<td>70% MEL</td>
<td>MRL+10% or MSOL</td>
<td>MRL</td>
</tr>
</tbody>
</table>

ECP.A.5.8.7 The tests are divided into the following three types:

(i) Frequency response compliance and volume tests as per ECP.A.5.8. Figure 1. These tests consist of frequency profile and ramp tests and adjustments to the target frequency setpoint as per ECP.5.8 Figure 3.

(ii) System islanding and step response tests as shown by ECP.A.5.8. Figure 2.

(iii) Frequency response tests in Limited Frequency Sensitive Mode (LFSM) to demonstrate LFSM-O and LFSM-U capability as shown by ECP.A.5.8 Figure 2.

ECP.A.5.8.8 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 Synchronous Power Generating Module or CCGT Module has stabilised or 90 seconds, whichever is the longer. 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. When witnessed by the Company each test should be carried out as a separate injection, when not witnessed by the Company there must be sufficient time allowed between tests for the Plant to have reached a stable steady state operating condition or 90 seconds, whichever is the longer.
Figure 1: Frequency Response Capability FSM Ramp Response Tests

<table>
<thead>
<tr>
<th>Load Point</th>
<th>LF Event Profile 1</th>
<th>LF Ramp -0.1Hz</th>
<th>LF Ramp +0.1Hz</th>
<th>LF Ramp -0.2Hz</th>
<th>LF Ramp +0.2Hz</th>
<th>HF Ramp -0.5Hz</th>
<th>HF Ramp +0.5Hz</th>
<th>LF Event Profile 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>MLP6</td>
<td></td>
<td></td>
<td>1</td>
<td>2</td>
<td>3</td>
<td></td>
<td></td>
<td>4</td>
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<tr>
<td>MLP5</td>
<td>5</td>
<td></td>
<td>6</td>
<td>7</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP4</td>
<td>8</td>
<td>9</td>
<td>10</td>
<td>11</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td>MLP3</td>
<td>15</td>
<td></td>
<td>16</td>
<td>17</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP2</td>
<td>18</td>
<td></td>
<td>19</td>
<td>20</td>
<td>21</td>
<td></td>
<td></td>
<td>22</td>
</tr>
<tr>
<td>MLP1</td>
<td>23</td>
<td></td>
<td>24</td>
<td>25</td>
<td></td>
<td></td>
<td></td>
<td>26</td>
</tr>
</tbody>
</table>
**Figure 2: Frequency Response Capability LFSM-O, LFSM-U and FSM 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 the Minimum Regulating 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 Minimum Regulating Level is not 20% then the injected step should be adjusted accordingly as shown in the example given below.

<table>
<thead>
<tr>
<th>Load Point</th>
<th>+2.0*</th>
<th>+0.02</th>
<th>-0.2</th>
<th>+0.2</th>
<th>-0.5</th>
<th>+0.5</th>
<th>+/-0.6-1.0</th>
<th>-2.0</th>
<th>±0**</th>
</tr>
</thead>
<tbody>
<tr>
<td>MLP6 LFSM</td>
<td>BC1</td>
<td>O</td>
<td>BC2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>L</td>
<td></td>
</tr>
<tr>
<td>MLP5</td>
<td>BC3</td>
<td></td>
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<tr>
<td>MLP4</td>
<td>BC4</td>
<td>A</td>
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<tr>
<td>MLP4 LFSM</td>
<td></td>
<td>D/E</td>
<td>F</td>
<td>G</td>
<td>H</td>
<td>I</td>
<td>BC5/6</td>
<td>J</td>
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<tr>
<td>MLP2</td>
<td>P</td>
<td>Q</td>
<td></td>
<td></td>
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<tr>
<td>MLP1</td>
<td></td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>K</td>
<td></td>
</tr>
</tbody>
</table>

**Initial Output**: 65%

**Minimum Regulating Level**: 20%

**Frequency Controller Droop**: 4%

**Frequency to be injected** = (0.65-0.20)x0.04x50 = 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 Synchronous Power Generating Module 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.

ECP.A.5.8.9 The Target Frequency adjustment facility should be demonstrated from the normal control point within the range of 49.9Hz to 50.1Hz by step changes to the Target Frequency setpoint as indicated in ECP.A.5.8 Figure 3 while operating at MLP4.

![ECP.A.5.8 Figure 3 – Target Frequency setting changes](image)

ECP.A.5.9 Compliance with ECC.6.3.3 Functionality Test

ECP.A.5.9.1 Where the plant design includes active control function or functions to deliver ECC.6.3.3 compliance, the Generator will propose and agree a test procedure with The Company, which will demonstrate how the Synchronous Power Generating Module Active Power output responds to changes in System Frequency and ambient conditions (e.g. by Frequency and temperature injection methods).

ECP.A.5.9.2 The Generator shall inform The Company if any load limiter control is additionally employed.

ECP.A.5.9.3 With the setpoint to the signals specified in ECP.A.4, The Company will agree with the Generator which additional control system parameters shall be monitored to demonstrate the functionality of ECC.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 6

COMPLIANCE TESTING OF POWER PARK MODULES

ECP.A.6.1 SCOPE

ECP.A.6.1.1 This Appendix outlines the general testing requirements for Power Park Modules and OTSDUA to demonstrate compliance with the relevant aspects of the Grid Code, Ancillary Services Agreement and Bilateral Agreement. 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 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 OTSDUA following successful completion of the first Power Park Module or OTSDUA tests in the case of a Power Station comprised of two or more Power Park Modules or OTSDUA which The Company reasonably considers to be identical.

If:

(a) the tests performed pursuant to ECP.A.6.1.1(iv) do not replicate the results contained in the Manufacturer's Data & Performance Report, or

(b) the tests performed pursuant to ECP.A.6.1.1(v) in respect of subsequent Power Park Modules or OTSDUA do not replicate the full tests for the first Power Park Module or OTSDUA, or

(c) any of the tests performed pursuant to ECP.A.6.1.1(iv) or ECP.A.6.1.1(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.

ECP.A.6.1.2 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 otherwise. Reactive Capability tests may be witnessed by The Company remotely from 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 OTSDUA 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 ECP.A.4.

ECP.A.6.1.3 In addition to the dynamic signals supplied in ECP.A.4 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

ECP.A.6.1.4 The Generator shall submit a detailed schedule of tests to The Company in accordance with CP.6.3.1, and this Appendix.

ECP.A.6.1.5 Prior to the testing of a Power Park Module or OTSDUA, the Generator shall complete the Integral Equipment Tests procedure in accordance with OC.7.5.

ECP.A.6.1.6 Partial Power Park Module or OTSDUA testing as defined in ECP.A.6.2 and ECP.A.6.3 is to be completed at the appropriate stage in accordance with ECP6.4A, ECP6.4B.

ECP.A.6.1.7 Full Power Park Module or OTSDUA testing as required by CP.7.2 is to be completed as defined in ECP.A.6.4 through to ECP.A.6.7.

ECP.A.6.1.8 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.

ECP.A.6.1.9 The Company will permit relaxation from the requirement ECP.A.6.2 to ECP.A.6.8 where an Equipment Certificate for the Power Park Module has been provided which details the characteristics from tests on a representative installation with the same equipment and settings and the performance of the Power Park Module can, in The Company’s opinion, reasonably represent that of the installed Power Park Module at that site. For Type B, Type C and Type D Power Park Modules, the relevant Equipment Certificate must be supplied in the Power Generating Module Document or Users Data File structure as applicable.

ECP.A.6.1.10 In the case of a co-located site, for example Electricity Storage Modules or Grid Forming Plant connected within a new or existing Power Station. The Company will accept test results to demonstrate compliance at the Grid Entry Point or User System Entry Point (if Embedded) through a combination of the capabilities of the Power Generating Modules (which could include a Grid Forming Plant) and Electricity Storage Modules or Electricity Storage Modules (which could include a Grid Forming Plant) and Generating Units or Power Park Modules. Generators should however be aware that for the purposes of testing, full Grid Code compliance should be demonstrated when, for example, the Electricity Storage Module or Grid Forming Plant is out of service and the remaining Power Generating Module is in service or the Electricity Storage Module or Grid Forming Plant is in service and the Power Generating Module is out of service. In the case of a Non-Synchronous...
Electricity Storage Module, The Company would expect the full set of tests to be completed as detailed in ECP.A.6.2 to ECP.A.6.8.

ECP.A.6.2  Pre 20% (or <50MW) Synchronised Power Park Module Basic Voltage Control Tests

ECP.A.6.2.1 Before 20% of the Power Park Module (or 50MW if less) has commissioned, either voltage control test ECP.A.6.5.6(i) or (ii) must be completed in accordance with ECP.6, ECP.6A or ECP.6B. In the case of an Offshore Power Park Module the test must be completed by the Generator undertaking OTSDUW or the Offshore Transmission Licencee under STCP19-5.

ECP.A.6.2.2 In the case of an Offshore Power Park Module which provides all or a portion of the Reactive Power capability as described in ECC.6.3.2.5.2 or ECP.6.3.2.6.3 and / or voltage control requirements as described in ECC.6.3.8.5 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.

ECP.A.6.3  Power Park Modules with Maximum Capacity ≥100MW Pre 70% Power Park Module Tests

ECP.A.6.3.1 Before 70% but with at least 50% of the Power Park Module commissioned the following Limited Frequency Sensitive tests as detailed in ECP.A.6.6.2 must be completed.

(a) BC3
(b) BC4

ECP.A.6.4  Reactive Capability Test

ECP.A.6.4.1 This section details the procedure for demonstrating the reactive capability of an Onshore Power Park Module or an Offshore Power Park Module or OTSDUA which provides all or a portion of the Reactive Power capability as described in ECC.6.3.2.5.2 or ECP.6.3.2.6.3 as applicable (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 ECC.6.3.2.5.1 and ECP.6.3.2.6.1 should complete the Reactive Power transfer / voltage control tests as per section ECP.A.6.8). 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 Maximum Capacity of the Power Park Module.

ECP.A.6.4.2 The tests shall be performed by modifying the voltage set-point of the voltage control scheme of the Power Park Module or OTSDUA by the amount necessary to demonstrate the required reactive range. This is to be conducted for the operating points and durations specified in ECP.A.6.4.5.

ECP.A.6.4.3 An Embedded Generator or Embedded Generator undertaking OTSDUW 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 or OTSDUA performance chart as specified in OC2.4.2.1
ECP.A.6.4.4 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.

ECP.A.6.4.5 The following tests shall be completed:

(i) Operation in excess of 60% Maximum Capacity and maximum continuous lagging Reactive Power for 30 minutes. For the avoidance of doubt this test must start with Active Power output in excess of 85% of Maximum Capacity of the Power Park Module as ECP.A.6.4.1 and must not fall below 60% of Maximum Capacity of the Power Park Module during the 30 minutes.

(ii) Operation in excess of 60% Maximum Capacity and maximum continuous leading Reactive Power for 30 minutes. For the avoidance of doubt this test must start with Active Power output in excess of 85% of Maximum Capacity of the Power Park Module as ECP.A.6.4.1 and must not fall below 60% of Maximum Capacity of the Power Park Module during the 30 minutes.

(iii) Operation at 50% Maximum Capacity and maximum continuous leading Reactive Power for 30 minutes.

(iv) Operation at 50% Maximum Capacity and maximum continuous lagging Reactive Power for 30 minutes.

(v) Operation at 20% Maximum Capacity and maximum continuous leading Reactive Power for 60 minutes.

(vi) Operation at 20% Maximum Capacity and maximum continuous lagging Reactive Power for 60 minutes.

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

(viii) Operation at the lower of the Minimum Regulating Level or 0% Maximum Capacity 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.

(ix) Operation at the lower of the Minimum Regulating Level or 0% Maximum Capacity 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.

In the case of a Non-Synchronous Electricity Storage Module, The Company shall have discretion to reduce the duration of the tests required in ECP.A.6.4.5 (i) – (viii) depending upon the capability of the energy store.

ECP.A.6 Within this ECP, 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 OTSDUA.

ECP.A.6.5 Voltage Control Tests
ECP.A.6.5.1 This section details the procedure for conducting voltage control tests on Onshore Power Park Modules or OTSDUA or an Offshore Power Park Module which provides all or a portion of the voltage control capability as described in ECC.6.3.8.5 (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 CC6.3.8.5) should complete the Reactive Power transfer / voltage control tests as per section ECP.A.6.8. 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 Maximum Capacity of the Onshore Power Park Module. An Embedded Generator or Embedded Generators undertaking OTSDUW 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.

ECP.A.6.5.2 The voltage control system shall be perturbed with a series of step injections to the Power Park Module voltage setpoint, and where possible, multiple upstream 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 setpoint of the Offshore Transmission Licensee control system.

ECP.A.6.5.3 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 ECP.A.6.5 Figure 1.

ECP.A.6.5.4 For a step injection into the Power Park Module or OTSDUA voltage setpoint, steps of ±1%, ±2% and ±4% (or larger if required by The Company) shall be applied to the voltage control system setpoint summing junction. The injection shall be maintained for a minimum of 10 seconds as per ECP.A.6.5 Figure 2.

ECP.A.6.5.5 Where the voltage control system comprises of discretely switched Plant and Apparatus (eg. mechanically switched shunt reactors or capacitors) additional tests will be required to demonstrate that overall performance of the voltage control system when switching these devices as part of the response is in accordance with Grid Code and Bilateral Agreement requirements.

ECP.A.6.5.6 Tests to be completed:

(i)

<table>
<thead>
<tr>
<th>Voltage</th>
<th>Time</th>
</tr>
</thead>
</table>
| ![Transformer tap sequence for voltage control tests](image)

ECP.A.6.5 Figure 1 – Transformer tap sequence for voltage control tests
ECP.A.6.5.7 In the case of OTSDUA, where the Bilateral Agreement specifies additional damping facilities, additional testing to demonstrate these damping facilities may be required.

ECP.A.6.5.8 In the case of Power Park Modules that do not provide voltage control down to zero Active Power a test to demonstrate the smooth transition from voltage control mode to unity Power Factor shall be carried out. The Power Park Module voltage setpoint should be altered to produce lagging Reactive Power or absorbing leading Reactive Power at a low Active Power level where voltage control is provided. The Power Park Module Active Power should then be reduced to zero Active Power as a ramp over a short period (60 seconds is suggested).

ECP.A.6.6 Frequency Response Tests

ECP.A.6.6.1 This section describes the procedure for performing frequency response testing on a 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 Maximum Capacity of the Power Park Module.

ECP.A.6.6.2 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 setpoint/feedback summing junction. If the injected frequency signal replaces rather than sums with the real System Frequency signal then the additional tests outlined in ECP.A.6.6.6 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.

ECP.A.6.6.3 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 ECC.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 ECP.A.6.6.6.

Preliminary Frequency Response Testing

ECP.A.6.6.4 Prior to conducting the full set of tests as per ECP.A.6.6.6, 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 forecast in order to generate at least 65% of Maximum Capacity of the Power Park Module. The following frequency injections shall be applied when operating at module load point 4.

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.

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.

<table>
<thead>
<tr>
<th>Test No (Figure 1)</th>
<th>Frequency Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>Inject -0.5Hz frequency fall over 10 sec</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold for a further 20 sec</td>
<td></td>
</tr>
<tr>
<td></td>
<td>At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold until conditions stabilise</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove the injected signal as a ramp over 10 seconds</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Inject - 0.5Hz frequency fall over 10 sec</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold until conditions stabilise</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove the injected signal as a ramp over 10 seconds</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Inject +0.5Hz frequency rise over 10 sec</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold until conditions stabilise</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove the injected signal as a ramp over 10 seconds</td>
<td></td>
</tr>
<tr>
<td>H</td>
<td>Inject - 0.5Hz frequency fall as a stepchange</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold until conditions stabilise</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove the injected signal as a stepchange</td>
<td></td>
</tr>
<tr>
<td>I</td>
<td>Inject +0.5Hz frequency rise as a stepchange</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Hold until conditions stabilise</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Remove the injected signal as a stepchange</td>
<td></td>
</tr>
</tbody>
</table>

The tests are divided into the following two types;

(i) Frequency response compliance and volume tests as per ECP.A.6.6. Figure 1. These tests consist of frequency profile and ramp tests and adjustments to target frequency setpoint as per ECP.A.6.6 Figure 3.
ECP.A.6.6.8 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 or 90 seconds, whichever is the longer. 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. When witnessed by The Company each test should be carried out as a separate injection, when not witnessed by The Company there must be sufficient time allowed between tests for the Active Power (MW) output of the Power Park Module to have stabilised or 90 seconds, whichever is the longer.

![Graph showing frequency response tests](image)

<table>
<thead>
<tr>
<th>Load Point</th>
<th>LF Event Profile 1</th>
<th>LF Ramp -0.1Hz</th>
<th>LF Ramp +0.1Hz</th>
<th>LF Ramp -0.2Hz</th>
<th>LF Ramp +0.2Hz</th>
<th>LF Ramp -0.5Hz</th>
<th>LF Ramp +0.5Hz</th>
<th>LF Event Profile 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>MLP6</td>
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<td>5</td>
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<td>6</td>
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</tr>
<tr>
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</tr>
<tr>
<td>MLP3</td>
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<td></td>
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<tr>
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<td>24</td>
<td>25</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

ECP.A.6.6. Figure 1 – Frequency Response Capability FSM Ramp Response tests

(ii) System islanding and step response tests as shown by ECP.A.6.6. Figure 2.

(iii) Frequency response tests in Limited Frequency Sensitive Mode (LFSM) to demonstrate LFSM-O and LFSM-U capability as shown by ECP.A.6.6 Figure 2.
* This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below the Minimum Regulating 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 Minimum Regulating Level is not 20% then the injected step should be adjusted accordingly as shown in the example given below.

<table>
<thead>
<tr>
<th>Initial Output</th>
<th>Minimum Regulating Level</th>
<th>Frequency Controller Droop</th>
<th>Frequency to be injected = (0.65 - 0.20) x 0.04 x 50 = 0.9Hz</th>
</tr>
</thead>
<tbody>
<tr>
<td>65%</td>
<td>20%</td>
<td>4%</td>
<td>0.9Hz</td>
</tr>
</tbody>
</table>

** 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.

ECP.A.6.6.9 The Target Frequency adjustment facility should be demonstrated from the
normal control point within the range of 49.9Hz to 50.1Hz by step changes to the Target Frequency setpoint as indicated in ECP.A.6.6 Figure 3 while operating at MLP4.

ECP.A.6.6. Figure 3 – Target Frequency setting changes

ECP.A.6.7 Fault Ride Through Testing

ECP.A.6.7.1 This section describes the procedure for conducting Fault Ride Through tests on a single Power Park Unit as required by ECP.7.2.2(d).

ECP.A.6.7.2 The test circuit will utilise the full Power Park Unit (e.g. in the case of a wind turbine it would include the full wind turbine nacelle structure, all inverters and converters along with step up transformer to medium voltage, all control systems including pitch control emulation) and shall be conducted with sufficient power input resource available to produce at least 95% of the Maximum 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 or other decoupling equipment to shield the connected network from voltage dips at the Power Park Unit terminals.

ECP.A.6.7.3 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 ECP.A.6.7.5. 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.

ECP.A.6.7.4 In addition to the signals outlined in ECP.A.4.2. 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 Power Generating Module.
(vii) MVAr – Reactive Power at the Power Generating Module.
(viii) Mechanical Rotor Speed
(ix) Real / reactive, current / power Setpoint 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.

ECP.A.6.7.5 The tests should be conducted for the times and fault types indicated in ECC.6.3.15 as applicable.

ECP.A.6.8 Reactive Power Transfer / Voltage Control Tests for Offshore Power Park Modules

ECP.A.6.8.1 In the case of an Offshore Power Park Module which provides all or a portion of the Reactive Power capability as described in ECP.6.3.2.5.2 or ECP.6.3.6.3 and / or voltage control requirements as described in ECC.6.3.8.5 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 ECP.A.6.8 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.

ECP.A.6.8.2 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 ECC.6.3.2.5 and ECC.6.3.2.6 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 Maximum Capacity of the Offshore Power Park Module.

ECP.A.6.8.3 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.

ECP.A.6.8.4 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 ECP.A.6.8 Figure 1.

ECP.A.6.8.5 The Active Power output of the Offshore Power Park Module should be varied by applying a sufficiently large step to the frequency controller Setpoint/feedback summing junction to cause a 10% change in output of the Maximum 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 ECP.A.6.6 are completed.

ECP.A.6.8.6 The following diagrams illustrate the tests to be completed:
ECP.A.6.8 Figure 1 – Transformer tap sequence for reactive transfer tests

ECP.A.6.8 Figure 2 – Active Power ramp for reactive transfer tests
APPENDIX 7

COMPLIANCE TESTING FOR HVDC EQUIPMENT

ECP.A.7.1 SCOPE

ECP.A.7.1.1 This Appendix outlines the general testing requirements for HVDC System Owners to demonstrate compliance with the relevant aspects of the Grid Code, Ancillary Services Agreement and Bilateral Agreement. 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 HVDC Equipment following successful completion of the first HVDC Equipment tests in the case of an installation comprising of two or more HVDC Systems or DC Connected Power Park Modules which The Company reasonably considers to be identical.

If:

(a) the tests performed pursuant to ECP.A.7.1.1(iv) in respect of subsequent HVDC Systems or DC Connected Power Park Modules do not replicate the full tests for the first HVDC Equipment, or

(b) any of the tests performed pursuant to ECP.A.7.1.1(iv) do not fully demonstrate compliance with the relevant aspects of the Grid Code, Ancillary Services Agreement and / or Bilateral

ECP.A.7.1.2 The HVDC System Owner is responsible for carrying out the tests set out in and in accordance with this Appendix and the HVDC System Owner retains the responsibility for the safety of personnel and plant during the test. The HVDC System 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 HVDC System Owner otherwise. Reactive Capability tests if required, may be witnessed by The Company remotely from The Company control centre. For all on site at The Company witnessed tests, the HVDC System Owner must ensure suitable representatives from the HVDC System Owner and / or HVDC Equipment 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 HVDC System Owner shall record all relevant test signals as outlined in ECP.A.4.
ECP.A.7.1.3 In addition to the dynamic signals supplied in ECP.A.4 the HVDC System 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.

ECP.A.7.1.4 The HVDC System Owner shall submit a detailed schedule of tests to The Company in accordance with CP.6.3.1, and this Appendix.

ECP.A.7.1.5 Prior to the testing of HVDC Equipment, the HVDC System Owner shall complete the Integral Equipment Tests procedure in accordance with OC.7.5.

ECP.A.7.1.6 Full HVDC Equipment testing as required by ECP.7.2 is to be completed as defined in ECP.A.7.2 through to ECP.A.7.5.

ECP.A.7.1.7 The Company will permit relaxation from the requirement ECP.A.7.2 to ECP.A.7.5 where an Equipment Certificate for HVDC Equipment has been provided which details the characteristics from tests on a representative installation with the same equipment and settings and the performance of the HVDC Equipment can, in The Company’s opinion, reasonably represent that of the installed HVDC Equipment at that site. The relevant Equipment Certificate must be supplied in the Users Data File structure.

ECP.A.7.1.8 The Company may agree a reduction from the requirement ECP.A.7.2 to ECP.A.7.5 for on-site testing where suitable factory acceptance testing on a representative installation with the same equipment and settings of the HVDC Equipment that can, in The Company’s opinion, reasonably represent the performance of the installed HVDC Equipment at that site. This is also conditional on The Company and the DC Converter Station owner agreeing sufficient on site testing of the fully commissioned DC Converter Station to demonstrate that the factory acceptance tests are valid. If in the reasonable opinion of The Company, the on-site testing does not demonstrate the factory acceptance tests are valid then the full set of on-site tests should be carried out.

ECP.A.7.2 Reactive Capability Test

ECP.A.7.2.1 This section details the procedure for demonstrating the reactive capability of HVDC Equipment. These tests should be scheduled at a time where there are sufficient MW resource forecasted in order to import and export full Maximum Capacity of the HVDC Equipment.

ECP.A.7.2.2 The tests shall be performed by modifying the voltage set-point of the voltage control scheme of the HVDC Equipment by the amount necessary to demonstrate the required reactive range. This is to be conducted for the operating points and durations specified in ECP.A.7.2.5.

ECP.A.7.2.3 Embedded HVDC System Owners 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 HVDC Equipment performance chart as specified in OC2.4.2.1

ECP.A.7.2.4 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 HVDC System Owner and The Company.

ECP.A.7.2.5 The following tests shall be completed for both importing and exporting of Active Power for a DC Converter:

(i) Operation at Maximum Capacity and maximum continuous lagging Reactive Power for 60 minutes.

(ii) Operation at Maximum Capacity and maximum continuous leading Reactive Power for 60 minutes.

(iii) Operation at 50% Maximum Capacity and maximum continuous leading Reactive Power for 60 minutes.

(iv) Operation at 50% Maximum Capacity and maximum continuous lagging Reactive Power for 60 minutes.

(v) Operation at Minimum Capacity and maximum continuous leading Reactive Power for 60 minutes.

(vi) Operation at Minimum Capacity and maximum continuous lagging Reactive Power for 60 minutes.

ECP.A.7.2.6 For the avoidance of doubt, lagging Reactive Power is the export of Reactive Power from the HVDC Equipment to the Total System and leading Reactive Power is the import of Reactive Power from the Total System to the HVDC Equipment.

ECP.A.7.3 Not used
ECP.A.7.4 Voltage Control Tests

ECP.A.7.4.1 This section details the procedure for conducting voltage control tests on HVDC Equipment. These tests should be scheduled at a time where there is sufficient MW resource in order to import and export Maximum Capacity of the HVDC Equipment. An Embedded HVDC System 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.

ECP.A.7.4.2 The voltage control system shall be perturbed with a series of step injections to the HVDC Equipment voltage Setpoint, and where possible, multiple up-stream transformer taps.

ECP.A.7.4.3 For steps initiated using network tap changers the HVDC System 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 ECP.A.7.4 Figure 1.

ECP.A.7.4.4 For step injection into the HVDC Equipment voltage setpoint, steps of ±1%, ±2% and ±4% shall be applied to the voltage control system setpoint summing junction. The injection shall be maintained for 10 seconds as per ECP.A.7.4 Figure 2.

ECP.A.7.4.5 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.

ECP.A.7.4.6 Tests to be completed:

(i) [Diagram]

ECP.A.7.4 Figure 1 – Transformer tap sequence for voltage control tests
ECP.A.7.5 Frequency Response Tests

ECP.A.7.5.1 This section describes the procedure for performing frequency response testing on HVDC Equipment. These tests should be scheduled at a time where there is sufficient MW resource in order to import and export full Maximum Capacity of the HVDC Equipment. The HVDC System 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.

ECP.A.7.5.2 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 Setpoint/feedback summing junction. If the injected frequency signal replaces rather than sums with the real System Frequency signal, then the additional tests outlined in ECP.A.7.5.6 shall be performed with the HVDC Equipment 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.

ECP.A.7.5.3 In addition to the frequency response requirements, it is necessary to demonstrate the HVDC Equipment ability to deliver a requested steady state power output which is not impacted by power source variation as per ECC.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 ECP.A.7.5.6.

Preliminary Frequency Response Testing

ECP.A.7.5.4 Prior to conducting the full set of tests as per ECP.A.7.5.6, HVDC System 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 is sufficient MW resource in order to export full Maximum Capacity from the HVDC Equipment. The following frequency injections shall be applied when operating at module load point 4.

<table>
<thead>
<tr>
<th>Test No</th>
<th>Frequency Injection</th>
<th>Notes</th>
</tr>
</thead>
</table>

ECP.A.7.4 Figure 2 – Step injection sequence for voltage control tests
8
- 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 as a ramp over 10 seconds

13
- Inject -0.5Hz frequency fall over 10 sec
- Hold until conditions stabilise
- Remove the injected signal as a ramp over 10 seconds

14
- Inject +0.5Hz frequency rise over 10 sec
- Hold until conditions stabilise
- Remove the injected signal as a ramp over 10 seconds

H
- Inject -0.5Hz frequency fall as a stepchange
- Hold until conditions stabilise
- Remove the injected signal as a stepchange

I
- Inject +0.5Hz frequency rise as a stepchange
- Hold until conditions stabilise
- Remove the injected signal as a stepchange

ECP.A.7.5.5
The recorded results (e.g. Finj, MW and control signals) should be sampled at a minimum rate of 1Hz 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 HVDC System 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

ECP.A.7.5.6
The tests are to be conducted at a number of different Module Load Points (MLP). In the case of HVDC Equipment the load points are conducted as shown below unless agreed otherwise by The Company.

| Module Load Point 6 (Maximum HVDC Active Power Transmission Capacity) | 100% MaxHAPTC |
| Module Load Point 5 | 90% MaxHAPTC |
| Module Load Point 4 | 80% MaxHAPTC |
| Module Load Point 3 | MinHAPTC + 0.6 x (80% MaxHAPTC – MinHAPTC) |
| Module Load Point 2 | MinHAPTC + 0.3 x (80% MaxHAPTC – MinHAPTC) |
| Module Load Point 1 (Minimum HVDC Active Power Transmission Capacity) | MinHAPTC |
ECP.A.7.5.7 The tests are divided into the following two types:

(i) Frequency response compliance and volume tests as per ECP.A.7.5. Figure 1. These tests consist of frequency profile and ramp tests and adjustments to Target Frequency setpoint as per ECP.A.7.5 Figure 3.
(ii) System islanding and step response tests as shown by ECP.A.7.5 Figure 2.

ECP.A.7.5. Fig 1 and 2 are shown for the Importing of Active Power, simulated frequency polarity should be reversed when exporting Active Power.

ECP.A.7.5.8 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 HVDC Equipment has stabilised or 90 seconds whichever is the longer. 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. When witnessed by The Company each test should be carried out as a separate injection, when not witnessed by The Company there must be sufficient time allowed between tests for the Active Power (MW) output of the HVDC Equipment to have stabilised or 90 seconds, whichever is the longer.
This will generally be +2.0Hz unless an injection of this size causes a reduction in plant output that takes the operating point below the **Minimum Regulating 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 Minimum Regulating Level is not 20%, then the injected step should be adjusted accordingly as shown in the example given below:

<table>
<thead>
<tr>
<th>Initial Output</th>
<th>Minimum Regulating Level</th>
<th>Frequency Controller Droop</th>
<th>Frequency to be injected</th>
</tr>
</thead>
<tbody>
<tr>
<td>65%</td>
<td>20%</td>
<td>4%</td>
<td>(0.65-0.20)x0.04x50 = 0.9Hz</td>
</tr>
</tbody>
</table>

** 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 HVDC Equipment 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.

**ECP.A.7.5.9** The target frequency adjustment facility should be demonstrated from the normal control point within the range of 49.9Hz to 50.1Hz by step changes to
the **Target Frequency** setpoint as indicated in ECP.A.7.5 Figure 3 while operating at MLP4.

ECP.A.7.5. Figure 3 – Target Frequency setting changes
APPENDIX 8
SIMULATION STUDIES AND COMPLIANCE TESTING FOR NETWORK OPERATORS AND NON-EMBEDDED CUSTOMERS PLANT AND APPARATUS

ECP.A.8.1 Compliance testing for disconnection and reconnection of Network Operator’s Plant and Apparatus

ECP.A.8.1.1 Network Operators shall comply with the following applicable requirements in respect of EU Grid Supply Points:

(i) Demand disconnection schemes;
(ii) Synchronising; and/or
(iii) low frequency demand disconnection;

ECP.A.8.1.2 The requirements for demand disconnection, other than low frequency demand disconnection, are pursuant to the requirements of the Bilateral Agreement. Any requirements for testing shall be agreed with the User where such requirements are applicable.

ECP.A.8.1.3 The requirements for synchronising (where applicable) shall be pursuant to the requirements of the Bilateral Agreement and ECC.6.2.3.10. Any requirements for testing (as applicable) shall be agreed with the User and carried out during the commissioning process.

ECP.A.8.1.4 Network Operators who are EU Code Users must demonstrate compliance with the low frequency demand disconnection requirements of ECC.6.4.3, ECC.A.5 and OC.6.6 for their entire distribution System.

ECP.A.8.1.5 An equipment certificate may be submitted to The Company instead of part of the tests provided for in ECP.A.8.1.1.

ECP.A.8.2 Compliance testing for operational metering at EU Grid Supply Points

ECP.A.8.2.1 The requirements for operational metering (where required) shall be pursuant to the requirements of the Bilateral Agreement and ECC.6.5.6. Any applicable requirements for testing shall be agreed with the User and carried out during the commissioning process. An Equipment Certificate may be used for this purpose where agreed with The Company.

ECP.A.8.3 Compliance testing for disconnection and reconnection of Non-Embedded Customers Plant and Apparatus

ECP.A.8.3.1 Non-Embedded Customers shall comply with the following requirements where applicable:

(i) Demand disconnection schemes;
(ii) Synchronising; and/or
(iii) low frequency demand disconnection;

ECP.A.8.3.2 The requirements for demand disconnection, other than low frequency demand disconnection, are pursuant to the requirements of the Bilateral Agreement. Any requirements for testing shall be agreed with the User.

ECP.A.8.3.3 The requirements for synchronising (where applicable) shall be pursuant to the requirements of the Bilateral Agreement and ECC.6.2.3.10. Any requirements for testing (as applicable) shall be agreed with the User and carried out during the commissioning process.
ECP.A.8.3.4 **Non-Embedded Customers** who are **EU Code Users** must demonstrate compliance with the low frequency demand disconnection requirements of ECC.6.4.3, ECC.A.5 and OC.6.6 of their **System**.

ECP.A.8.3.5 An equipment certificate may be submitted to **The Company** instead of part of the tests provided for in ECP.A.8.3.1.

ECP.A.8.4 Compliance testing for operational metering on Non-Embedded Customers Plant and Apparatus

ECP.A.8.4.1 The requirements for operational metering (where required)) shall be pursuant to the requirements of the Bilateral Agreement and ECC.6.5.6. Any applicable requirements for testing shall be agreed with the **User** and carried out during the commissioning process. An Equipment Certificate may be used for this purpose where agreed with **The Company**.ECP.A.8.5 Common Provisions on Compliance Simulations

ECP.A.8.5.1 **Users** are required to provide simulation studies or equivalent information to the satisfaction of **The Company** in the following circumstances.

(i) a new connection to the **Transmission System** is required forming part of an **EU Grid Supply Point**;

(ii) a **Substantial Modification** takes place at an **EU Grid Supply Point**

(iii) **The Company** becomes aware of a potential non-compliance by the **Network Operator** or **Non-Embedded Customer** at an **EU Grid Supply Point**.

ECP.A.8.5.2 Notwithstanding the requirements of ECP.A.8.5.1, **The Company** shall be entitled to:-

(a) Allow the **Network Operator** or **Non-Embedded Customer** to carry out an alternative set of simulations (or equivalent information) provided that they demonstrate that the **Network Operators** or **Non-Embedded Customers Plant** and **Apparatus** is capable of satisfying the applicable requirements of the **Data Registration Code**.

(b) Require the **Network Operator** or **Non-Embedded Customer** to carry out additional or alternative simulations (or equivalent information) to those specified in ECP.A.8.5.1 where they would otherwise be insufficient to demonstrate compliance.

(c) **The Company** may check that the **Network Operator** or **Non-Embedded Customer** complies with the requirements of the **Grid Code** by carrying out its own compliance simulations based on the simulation reports, models and test measurements submitted under the **Data Registration Code**.

ECP.A.8.5.3 **The Company** will supply (under PC.A.8) upon request to the **Network Operator** or **Non-Embedded Customer**, data to enable the **Network Operator** or **Non-Embedded Customer** to carry out the required simulations or supply the equivalent information required under the **Data Registration Code**.

ECP.A.8.6 Compliance simulations for EU Grid Supply Points

ECP.A.8.6.1 **Networks Operators** who are also **EU Code Users**, are required to provide simulation studies (or make available equivalent information) at each **EU Grid Supply Point** to demonstrate compliance with the Reactive Power capability requirements set out in ECC.6.4.5. The study or equivalent information provided shall include a steady state simulation model under both maximum
and minimum demand conditions. In addition, the model or equivalent information provided shall include the conditions when the \textit{Reactive Power} export is at an \textit{Active Power} flow of less than 25\% of the \textit{Maximum Import Capability} as detailed under ECC.6.4.5.2. In all cases the models or equivalent information submitted shall be agreed and approved with The Company.

**ECP.A.8.7** Compliance simulations for Non-Embedded Customers Plant and Apparatus

**ECP.A.8.7.1** None Embedded Customers who are also EU Code Users are required at each EU Grid Supply Point to provide simulation studies (or equivalent information) to demonstrate compliance with the \textit{Reactive Power} capability requirements set out in ECC.6.4.5. The study or equivalent information provided shall include a steady state simulation model under both maximum and minimum demand conditions and with and without on-site generation. In all cases the models or equivalent information submitted shall be agreed and approved with The Company.

**ECP.A.8.8** Compliance monitoring at EU Grid Supply Points

**ECP.A.8.8.1** To satisfy the requirements of ECC.6.4.5, EU Code Users who are either Network Operators or Non-Embedded Customers shall ensure their Plant and Apparatus is equipped (where applicable), with the necessary equipment to measure the \textit{Active Power} and \textit{Reactive Power}, at each EU Grid Supply Point. The requirement for and time frame for compliance monitoring shall be agreed between The Company and the EU Code User for each EU Grid Supply Point.
APPENDIX 9
COMPLIANCE TESTING FOR GRID FORMING PLANT

ECP.A.9.1 SCOPE

ECP.A.9.1.1 This Appendix outlines the general testing requirements for Users or Non-CUSC Parties to demonstrate compliance with the relevant aspects of the Grid Code, Ancillary Services Agreement and Bilateral Agreement. The tests specified in this Appendix will normally be sufficient to demonstrate compliance of a GBGF-I, however The Company may:

i) agree to 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 or additional functions to prove the capability of the GBGF-I is required by the Bilateral Agreement or included in the control scheme; and/or

iv) agree a reduced set of tests for the subsequent GBGF-I following successful completion of the first Grid Forming tests in the case of an installation comprising of two or more GBGF-Is which The Company reasonably considers to be identical if:

(a) the tests performed pursuant to ECP.A.9.1.9 in respect of subsequent GBGF-I Plants do not replicate the full tests for the first GBGF-I; or

(b) any of the tests performed pursuant to ECP.A.9.1.9 do not fully demonstrate compliance with the relevant aspects of the Grid Code, Ancillary Services Agreement and/or Bilateral Agreement.

ECP.A.9.1.2 The User or Non-CUSC Party is responsible for carrying out the tests set out in and in accordance with this Appendix and the User or Non-CUSC Party 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 User or Non-CUSC Party otherwise. For all on site at The Company witnessed tests, the User or Non-CUSC Party must ensure suitable representatives from the Grid Forming Plant’s 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 User or Non-CUSC Party shall record all relevant test signals as outlined in ECP.A.4.

ECP.A.9.1.3 In addition to the dynamic signals supplied in ECP.A.4, the User or Non-CUSC Party 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, if used.
(ii) Number of Grid Forming Units in operation.

ECP.A.9.1.4 The User or Non-CUSC Party shall submit a detailed schedule of tests to The Company in accordance with ECP.6.3.1, and this Appendix.

ECP.A.9.1.5 Prior to the testing of the GBGF-I the User or Non-CUSC Party shall complete
the Integral Equipment Tests procedure in accordance with OC.7.5.

ECP.A.9.1.6 Full GBGF-I testing as required by ECP.7.2 is to be completed as defined in ECP.A.9.1.9.

ECP.A.9.1.7 The Company will permit relaxation from the requirements in ECP.A.9.1.9 where an Equipment Certificate for GBGF-I has been provided which details the characteristics from tests on a representative installation with the same equipment and settings and the performance of the GBGF-I can, in The Company's opinion, reasonably represent that of the installed GBGF-I at that site. The relevant Equipment Certificate must be supplied in the Users Data File Structure.

ECP.A.9.1.8 Prior to any GBGF-I tests taking place, the User or Non-CUSC Party shall have completed the relevant compliance tests on the GBGF-I, Power Generating Module or Generating Unit as required under ECP.A.5 or OC5.A.2 (as relevant) or Power Park Module as required under ECP.A.6 or OC5.A.3 (as applicable) or HVDC Systems or DC Converters as required under ECP.A.7 or OC5.A.4 (as applicable).

ECP.A.9.1.9 Demonstration of Grid Forming Capability

ECP.A.9.1.9.1 This section details the procedure for demonstrating Active ROCOF Response Power. Ideally if the test is being completed as part of a type test on an isolated network and it is possible to change the frequency of the isolated network then the tests should be completed using a variable network Frequency. The Company recognise that it is not possible in a large number of cases to adjust the network frequency of the network to which the Grid Forming Plant is connected. If a suitable test network is not available, performance of the GBGF-I will need to be demonstrated through online monitoring as detailed in CC.6.6 or ECC.6.6 and simulation studies as required under ECP.A.3.9.4 will be required during the Interim Operational Notification Process as provided for under CP.6 or ECP.6 (as applicable).

ECP.A.9.1.9.2 In this test, with the Grid Forming Plant initially running at full load, the test network frequency is ideally increased from 50Hz to 51 Hz at a rate of 1Hz/s with measurements of the Grid Forming Plant's Active ROCOF Response Power, System Frequency and time in (ms). The test is required to assess correct operation of the Grid Forming Plant without saturating. This test is then repeated for a 50 Hz to 49 Hz at a rate of 1Hz/s.

ECP.A.9.1.9.3 These tests are required to assess the Grid Forming Plant's withstand capabilities under extreme System Frequencies.

(i) For Grid Forming Plant comprising a GBGF-I the frequency of the test network is increased from 50Hz to 52Hz at a rate of 2Hz/s with measurements of the Grid Forming Plant's Active ROCOF Response Power, System Frequency and time in (ms).

(ii) For a Grid Forming Plant comprising a GBGF-I the frequency of the test network is increased from 50Hz to 52Hz at a rate of 1Hz/s with measurements of the Grid Forming Plant's Active ROCOF Response Power, System Frequency and time in (ms).

(iii) For Grid Forming Plant comprising a GBGF-I the frequency of the test network is decreased from 50Hz to 47 Hz at a rate of 2Hz/s with measurements of the Grid Forming Plant's Active ROCOF Response Power, System Frequency and time in (ms).
(iii) For **Grid Forming Plant** comprising a GBGF-I the frequency of the test network is decreased from 50Hz to 47 Hz at a rate of 1Hz/s with measurements of the **Grid Forming Plant’s Active ROCOF Response Power, System Frequency** and time in (ms).

ECP.A.9.1.9.4 This test is to demonstrate the **Grid Forming Plant’s ability to supply Active ROCOF Response Power over the full System Frequency range**.

(a) With the frequency of the test network set to 50Hz, the GBGF-I should be initially running at 75% **Maximum Capacity** or **Registered Capacity**, zero MVAr output and both **Limited Frequency Sensitive Mode** and **Frequency Sensitive Mode** disabled.

(b) The frequency is then increased from 50Hz to 52Hz at a rate of 1Hz/s over a 2 second period. Allow conditions to stabilise for 5 seconds and then decrease the frequency from 52Hz to 47Hz at a rate of 1Hz/s over a 5 second period. Allow conditions to stabilise.

(c) Record results of **Active ROCOF Response Power, Reactive Power**, voltage and frequency.

(d) The test now needs to be re-run in the opposite direction. The same initial conditions should be applied as per ECP.A.9.1.9.4(a).

(e) The frequency is then decreased from 50Hz to 47Hz at a rate of 1Hz/s over a 3 second period. Allow conditions to stabilise for 5 seconds and then increase the frequency from 47Hz to 52Hz at a rate of 1Hz/s over a 5 second period. Allow conditions to stabilise.

(f) Record results of **Active ROCOF Response Power, Reactive Power**, voltage and frequency.

ECP.A.9.1.9.5 This test is to demonstrate the **Grid Forming Plant’s ability to supply Active Phase Jump Power under normal operation**.

(a) With the frequency of the test network set to 50Hz, the GBGF-I should be initially running at **Maximum Capacity** or **Registered Capacity** or at its agreed deloaded point, zero MVAr output and all control actions (e.g. **Limited Frequency Sensitive Mode**, **Frequency Sensitive Mode** and voltage control) disabled.

(b) Apply a positive phase jump of up to the **Phase Jump Angle Limit** at the **Grid Entry Point** or **User System Entry Point** (if Embedded).

(c) This test can then be repeated by injecting the same angle into the **Grid Forming Plant’s control system** (as indicatively shown in Figure ECP.A.9.1.9.5). This specific test can be repeated on site as required for a routine performance evaluation test. It should be noted that Figure ECP.A.9.1.9.5 is a simplified representation. Each **Grid Forming Plant Owner** can use their own design, that may be very different to Figure ECP.A.9.1.9.5 but should contain all relevant functions that can include test points and other equivalent data and documentation. Any additional signals, measurements, parameters and tests shall be agreed between the **Grid Forming Plant Owner** and **The Company**.

(d) Repeat tests (b) and (c) with a negative injection up to the **Phase Jump Angle Limit**.

(e) Record traces of **Active Power, Reactive Power**, voltage, current and frequency for a period of 10 seconds after the step change in phase has been applied.
As part of these tests, the corresponding **Active Power** change resulting from a phase shift will be a function of the local reactance and the location of where the phase shift is applied in addition to any additional upstream impedance between the GBGF-I and phase step location.

**ECP.A.9.1.9.6** This test is to demonstrate the **Grid Forming Plant's** ability to supply **Active Phase Jump Power** under extreme conditions. Where it is not possible to undertake this test as part of a type test, **The Company** will accept demonstration through a combination of simulation studies as required under ECP.A.3.9.4(vi) and online monitoring as required under ECC.6.6.1.9.

(a) With the frequency of the test network set to 50Hz, the **Grid Forming Plant** should be initially running at its **Minimum Stable Operating Level** or **Minimum Stable Generation**, zero MVAr output and all control actions (e.g., Limited Frequency Sensitive Mode, Frequency Sensitive Mode and voltage control) disabled.

(b) Apply a phase jump of 60 degrees at the connection point of the GBGF-I or into the **Grid Forming Plant**'s control system as shown in Figure ECP.A.9.1.9.5.

(c) Record traces of **Active Power**, **Reactive Power**, voltage, current and frequency for a period of 10 seconds after the step change in phase has been applied.

(d) Repeat steps (a), (b) and (c) of ECP.A.9.1.9.6 but on this occasion apply a phase jump equivalent to the positive **Phase Jump Angle Limit** at the Grid.

**ECP.A.9.1.9.7** This test is to demonstrate the GBGF-I's ability to supply **Active Phase Jump Power, Fault Ride Through** and **GBGF Fast Fault Current Injection** during a faulted condition. Where it is not possible to undertake this test as part of a type test, **The Company** will accept demonstration through a combination of simulation studies as required under ECP.A.3.9.4(vii) and online monitoring as required under CC.6.6 and ECC.6.6.1.9.

(a) With the frequency set to 50Hz, the **Grid Forming Plant** should be initially running at its **Maximum Capacity** or **Registered Capacity** or at an alternative loading point as agreed with **The Company**, zero MVAr output and all control actions (e.g., Limited
Frequency Sensitive Mode, Frequency Sensitive Mode and voltage control) disabled.

(b) Apply a solid three phase short circuit fault at the connection point in the test network forming part of the type test for 140ms or alternatively the equivalent of a zero retained voltage for 140ms.

(c) Record traces of Active Power, Reactive Power, voltage, current and frequency for a period of 10 seconds after the fault has been applied.

(d) Repeat steps (a) to (c) but on this occasion with fault ride through, GBGF Fast Fault Current Injection Limited Frequency Sensitive Mode and voltage control switched into service.

(e) Record traces of Active Power, Reactive Power, voltage, current and frequency for a period of 10 seconds after the step change in phase has been applied and confirm correct operation.

ECP.A.9.1.9.8 The final test required is to demonstrate the GBGF-I is capable of contributing to Active Damping Power. The Grid Forming Plant Owner should configure their Grid Forming Plant in form or equivalent (as agreed with The Company) as shown in Figure ECP.A.3.9.6(a) or Figure ECP.A.3.9.6(b) as applicable. Each Grid Forming Plant Owner can use their own design, that may be very different to Figures ECP.A.3.9.6(a) or ECP.A.3.9.6 (b) but should contain all relevant functions.

As part of this test, the Grid Forming Plant Owner is required to inject a signal into the Grid Forming Plant controller. The results supplied need to verify the following criteria:

i) Inject a Test Signal into the Grid Forming Plant controller to demonstrate the Active Control Based Power output is supplied below the 5Hz bandwidth limit. An acceptable performance will be judged where the overshoot or decay matches the Damping Factor declared by the Grid Forming Plant Owner as submitted in PC.A.5.8.1 in addition to assessment against the requirements of CC.A.6.2.6.1 or ECC.A.6.2.6.1 or CC.A.7.2.2.5 or ECC.A.7.2.5.2 as applicable.

<END OF ECP>
## OPERATING CODE NO. 1 (OC1)
### DEMAND FORECASTS

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OC1.1  INTRODUCTION

OC1.1.1  Operating Code No. 1 ("OC1") is concerned with Demand forecasting for operational purposes. In order to match generation output with Demand for electricity it is necessary to undertake Demand forecasting. It is also necessary to undertake Demand forecasting of Reactive Power.

OC1.1.2  In the Operational Planning Phase, Demand forecasting shall be conducted by The Company taking account of Demand forecasts furnished by Network Operators, who shall provide The Company with information in the form set out in this OC1. The data supplied under the PC is also taken into account.

OC1.1.3  In the Programming Phase and Control Phase, The Company will conduct its own Demand forecasting taking into account information to be furnished by Suppliers and Network Operators and the other factors referred to in OC1.6.1.

OC1.1.4  In this OC1, the point of connection of the External Interconnection to the National Electricity Transmission System shall be considered as a Grid Supply Point. Reactive Power Demand includes the series Reactive losses of the User's System but excludes any network susceptance and any Reactive compensation on the User's System. The Company will obtain the lumped network susceptance and details of Reactive compensation from the requirements to submit data under the PC.

OC1.1.5  Data relating to Demand Control should include details relating to MW.

OC1.1.6  OC1 deals with the provision of data on Demand Control in the Operational Planning Phase, the Programming Phase and the Post-Control Phase, whereas OC6 (amongst other things) deals with the provision of data on Demand Control following the Programming Phase and in the Control Phase.

OC1.1.7  In this OC1, Year 0 means the current Financial Year at any time, Year 1 means the next Financial Year at any time, Year 2 means the Financial Year after Year 1, etc.

OC1.1.8  References in OC1 to data being supplied on a half hourly basis refer to it being supplied for each period of 30 minutes ending on the hour and half-hour in each hour.

OC1.2  OBJECTIVE

The objectives of OC1 are to:

OC1.2.1  enable the provision of data to The Company by Users in the Programming Phase, Control Phase and Post-Control Phase; and

OC1.2.2  provide for the factors to be taken into account by The Company when Demand forecasting in the Programming Phase and Control Phase.

OC1.3  SCOPE

OC1 applies to The Company and to Users which in this OC1 means:

(a)  Network Operators, and

(b)  Suppliers.

OC1.4  DATA REQUIRED BY THE COMPANY IN THE OPERATIONAL PLANNING PHASE

OC1.4.1  (a) Each User, as specified in (b) below, shall provide The Company with the data requested in OC1.4.2 below.

(b) The data will need to be supplied by each Network Operator directly connected to the National Electricity Transmission System in relation to Demand Control and in relation each Generator with respect to the output of Embedded Medium Power Stations within its System.

OC1.4.2  (a) Data
By calendar week 28 each year each Network Operator will provide to The Company in writing the forecast information listed in (c) below for the current Financial Year and each of the succeeding five Financial Years.

(b) Data Providers

In circumstances when the busbar arrangement at a Grid Supply Point is expected to be operated in separate sections, separate sets of forecast information for each section will be provided to The Company.

(c) Embedded Medium Power Station Output and Demand Control

For the specified time of the annual peak half hour National Electricity Transmission System Demand, as specified by The Company under PC.A.5.2.2, the output of Embedded Medium Power Stations and forecasts of Demand to be relieved by Demand Control on a Grid Supply Point basis giving details of the amount and duration of the Demand Control.

OC1.5 DATA REQUIRED BY THE COMPANY IN THE PROGRAMMING PHASE, CONTROL PHASE AND POST-CONTROL PHASE

OC1.5.1 Programming Phase

For the period of 2 to 8 weeks ahead the following will be supplied to The Company in writing by 1000 hours each Monday:

(a) Demand Control

Each Network Operator will supply MW profiles of the amount and duration of their proposed use of Demand Control which may result in a Demand change equal to or greater than the Demand Control Notification Level (averaged over any half hour on any Grid Supply Point) on a half hourly and Grid Supply Point basis;

(b) Medium Power Station Operation

Each Network Operator will, if reasonably required by The Company, supply MW schedules for the operation of Embedded Medium Power Stations within its System on a half hourly and Grid Supply Point basis.

OC1.5.2 For the period 2 to 12 days ahead the following will be supplied to The Company in writing by 1200 hours each Wednesday:

(a) Demand Control

Each Network Operator will supply MW profiles of the amount and duration of their proposed use of Demand Control which may result in a Demand change equal to or greater than the Demand Control Notification Level (averaged over any half hour on any Grid Supply Point) on a half hourly and Grid Supply Point basis;

(b) Medium Power Station Operation

Each Network Operator will, if reasonably required by The Company, supply MW schedules for the operation of Embedded Medium Power Stations within its System on a half hourly and Grid Supply Point basis.

OC1.5.3 Medium Power Station Output

Each Network Operator will, if reasonably required by The Company, supply The Company with MW schedules for the operation of Embedded Medium Power Stations within its System on a half hourly and Grid Supply Point basis in writing by 1000 hours each day (or such other time specified by The Company) from time to time for the next day (except that it will be for the next 3 days on Fridays and 2 days on Saturdays and may be longer (as specified by The Company at least one week in advance) to cover holiday periods);

OC1.5.4 Other Codes
Under OC6 each Network Operator will notify The Company of their proposed use of Demand Control (which may result in a Demand change equal to or greater than the Demand Control Notification Level), and under BC1, each Supplier will notify The Company of their proposed use of Customer Demand Management (which may result in a Demand change equal to or greater than the Customer Demand Management Notification Level) in this timescale.

OC1.5.5 Control Phase

OC1.5.5.1 Demand Control

Under OC6, each Network Operator will notify The Company of any Demand Control proposed by itself which may result in a Demand change equal to or greater than the Demand Control Notification Level averaged over any half hour on any Grid Supply Point which is planned after 1000 hours, and of any changes to the planned Demand Control notified to The Company prior to 1000 hours as soon as possible after the formulation of the new plans;

OC1.5.5.2 Customer Demand Management

(a) Each Supplier will notify The Company of any Customer Demand Management proposed by itself which may result in a Demand change equal to or greater than the Customer Demand Management Notification Level averaged over any half hour on any Grid Supply Point which is planned to occur at any time in the Control Phase and of any changes to the planned Customer Demand Management already notified to The Company as soon as possible after the formulation of the new plans.

(b) The following information is required on a Grid Supply Point and half-hourly basis:

(i) the proposed date, time and duration of implementation of Customer Demand Management; and

(ii) the proposed reduction in Demand by use of Customer Demand Management.

OC1.5.5.3 Load Management Blocks

In Scotland, by 11:00 each day, each Supplier who controls a Load Management Block of Demand with a capacity of 5MW or more shall submit to The Company a schedule of its proposed switching times and profiles in respect of each block for the next day.

OC1.5.6 Post-Control Phase

The following will be supplied to The Company in writing by 0600 hours each day in respect of Active Power data and by 1000 hours each day in respect of Reactive Power data:

(a) Demand Control

Each Network Operator will supply MW profiles for the previous calendar day of the amount and duration of Demand reduction achieved by itself from the use of Demand Control equal to or greater than the Demand Control Notification Level (averaged over any half hour on any Grid Supply Point), on a half hourly and Grid Supply Point basis.

(b) Customer Demand Management

Each Supplier will supply MW profiles of the amount and duration of Demand reduction achieved by itself from the use of Customer Demand Management equal to or greater than the Customer Demand Management Notification Level (averaged over any half hour on any Grid Supply Point) on a half hourly and Grid Supply Point basis during the previous calendar day.
THE COMPANY FORECASTS

OC1.6.1 The following factors will be taken into account by The Company when conducting National Electricity Transmission System Demand forecasting in the Programming Phase and Control Phase:

(a) Historic Demand data (this includes National Electricity Transmission System Losses).

(b) Weather forecasts and the current and historic weather conditions.

(c) The incidence of major events or activities which are known to The Company in advance.

(d) Anticipated interconnection flows across External Interconnections.

(e) Demand Control equal to or greater than the Demand Control Notification Level (averaged over any half hour at any Grid Supply Point) proposed to be exercised by Network Operators and of which The Company has been informed.

(f) Customer Demand Management equal to or greater than the Customer Demand Management Notification Level (averaged over any half hour at any Grid Supply point) proposed to be exercised by Suppliers and of which The Company has been informed.

(g) Other information supplied by Users.

(h) Anticipated Pumped Storage Unit demand.

(i) the sensitivity of Demand to anticipated market prices for electricity.

(j) BM Unit Data submitted by BM Participants to The Company in accordance with the provisions of BC1 and BC2.

(k) Demand taken by Station Transformers

(l) Anticipated Electricity Storage Module demand

Taking into account the factors specified in OC1.6.1 The Company uses Demand forecast methodology to produce forecasts of National Electricity Transmission System Demand. A written record of the use of the methodology must be kept by The Company for a period of at least 12 months.

The methodology will be based upon factors (a), (b) and (c) above to produce, by statistical means, unbiased forecasts of National Demand. National Electricity Transmission System Demand will be calculated from these forecasts but will also take into account factors (d), (e), (f), (g), (h), (i) and (j) above. No other factors are taken into account by The Company, and it will base its National Electricity Transmission System Demand forecasts on those factors only.

< END OF OPERATING CODE NO. 1 >
# OPERATING CODE NO. 2

(OC2)

OPERATIONAL PLANNING AND DATA PROVISION

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OC2.1 INTRODUCTION

OC2.1.1 Operating Code No. 2 ("OC2") is concerned with:

(a) the co-ordination of the release of Power Generating Modules (including DC Connected Power Park Modules), Synchronous Generating Units and Power Park Modules, External Interconnections, the National Electricity Transmission System and Network Operators' Systems for construction, repair and maintenance;

(b) provision by The Company of the Surplus for the National Electricity Transmission System;

(c) the provision by Generators of Generation Planning Parameters for Generators, including Synchronous Power Generating Module Planning Matrices, CCGT Module Planning Matrices and Power Park Module Planning Matrices, to The Company for planning purposes only; and

(d) the agreement for release of Existing Gas Cooled Reactor Plant for outages in certain circumstances.

OC2.1.2 (a) Operational Planning involves 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 Power Generating Modules (including DC Connected Power Park Modules), Generating Units, Power Park Modules, External Interconnections, HVDC Systems and DC Converters, and of parts of the National Electricity Transmission System and of parts of Network Operators’ Systems which is 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.

(b) In general terms, there is an "envelope of opportunity" for the release of Power Generating Modules (including DC Connected Power Park Modules), Synchronous Generating Units, Power Park Modules and External Interconnections, and for the release of parts of the National Electricity Transmission System and parts of the Network Operator's User Systems for outages. The envelope is defined by the difference between the total generation output expected from Large Power Stations, Medium Power Stations and Demand, the operational planning margin and taking into account External Interconnections.

OC2.1.3 In this OC2, for the purpose of Generator and Interconnector Owner outage co-ordination, Year 0 means the current calendar year at any time, Year 1 means the next calendar year at any time, Year 2 means the calendar year after Year 1, etc. For the purpose of Transmission outage planning, Year 0 means the current Financial Year at any time, Year 1 means the next Financial Year at any time, Year 2 means the Financial Year after Year 1, etc. References to 'weeks' in OC2 are to calendar weeks as defined in ISO 8601.

OC2.1.4 References in OC2 to a Generator's and Interconnector Owner's "best estimate" shall be that Generator's or Interconnector Owner's best estimate acting as a reasonable and prudent Generator or Interconnector Owner in all the circumstances.

OC2.1.5 References to The Company planning the National Electricity Transmission System outage programme on the basis of the Final Generation Outage Programme, are to The Company planning against the Final Generation Outage Programme current at the time it so plans.

OC2.1.6 Where in OC2, data is required to be submitted or information is to be given on a particular weekday, that data does not need to be submitted and that information does not need to be given on that day if it is not a Business Day or it falls within a holiday period (the occurrence and length of which shall be determined by The Company, in its reasonable discretion, and notified to Users). Instead, that data shall be submitted and/or that information shall be given on such other Business Day as The Company shall, in its reasonable discretion, determine. However, The Company may determine that that data and/or information need not be submitted or given at all, in which case it shall notify each User as appropriate.
In Scotland, it may be possible with the agreement of The Company to reduce the administrative burden for Users in producing planning information where either the output or demand is small.

**OBJECTIVE**

OC2.2.1 (a) The objective of OC2 is to seek to enable The Company to harmonise outages of Power Generating Modules (including DC Connected Power Park Modules), Generating Units, Power Park Modules and External Interconnections in order that such outages are co-ordinated (taking account of Embedded Medium Power Stations) between Generators and Network Operators, and that such outages are co-ordinated taking into account National Electricity Transmission System outages and other System outages, so far as possible to minimise the number and effect of constraints on the National Electricity Transmission System or any other System.

(b) In the case of Network Operator User Systems directly connected to the National Electricity Transmission System, this means in particular that there will also need to be harmonisation of outages of Embedded Power Generating Modules, Embedded Synchronous Generating Units and Embedded Power Park Modules, and National Electricity Transmission System outages, with Network Operators in respect of their outages on those Systems.

OC2.2.2 The objective of OC2 is also to enable the provision by The Company of the Surplus for the National Electricity Transmission System.

OC2.2.3 A further objective of OC2 is to provide for the agreement for outages for Existing Gas Cooled Reactor Plant in certain circumstances and to enable a process to be followed in order to provide for that.

**SCOPE**

OC2.3.1 OC2 applies to The Company and to Users which in OC2 means:

(a) Generators, only in respect of their Large Power Stations or their Power Stations which are directly connected to National Electricity Transmission System (and the term Generator in this OC2 shall be construed accordingly);

(b) Network Operators; and

(c) Non-Embedded Customers; and

(d) HVDC System Owners and DC Converter Station owners; and

(e) Interconnector Owners in respect of their External Interconnections.

OC2.3.2 The Company may provide to the Relevant Transmission Licensees any data which has been submitted to The Company by any Users in respect of Relevant Units pursuant to the following paragraphs of the OC2.

OC2.4.1.2.1

OC2.4.1.3.2 (a)

OC2.4.1.3.2 (b)

OC2.4.1.3.3

OC2.4.2.1 (a)

OC2.3.3 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.

**PROCEDURE**

OC2.4.1 Co-ordination of Outages

OC2.4.1.1 Under OC2 the interaction between The Company and Users will be as follows:
(a) Each Generator, and each Interconnector Owner and The Company in respect of outages of Power Generating Modules (including DC Connected Power Park Modules), Synchronous Generating Units, Power Park Modules and External Interconnection Circuits and in respect of outages of other Plant and/or Apparatus directly connected to the National Electricity Transmission System;

(b) The Company and each Generator and each Interconnector Owner in respect of National Electricity Transmission System outages relevant to each Generator (other than in respect of Embedded Small Power Stations or Embedded Medium Power Stations) and Interconnector Owner;

(c) The Company and each Network Operator in respect of outages of all Embedded Large Power Stations and in respect of outages of other Plant and/or Apparatus relating to such Embedded Large Power Stations;

(d) The Company and each Network Operator and each Non-Embedded Customer in respect of National Electricity Transmission System outages relevant to the particular Network Operator or Non-Embedded Customers;

(e) Each Network Operator and each Non-Embedded Customer and The Company in respect of User System outages relevant to The Company; and

in respect of Network Operators only, outages of the Network Operator’s User System that may impact upon an Offshore Transmission System connected to that Network Operator’s User System.

OC2.4.1.2 Data Provision of Output Usable of Power Generating Modules, Generating Units, External Interconnection Circuits and Power Park Modules and the Publication of National Surplus.

OC2.4.1.2.1 In the event that:

a) a Generator referred to in OC2.3.1(a) experiences any unplanned change to the availability of a Generating Unit and/or Power-Generating Module and/or Power Park Module or makes a future plan which would impact the availability of a Generating Unit and/or Power-Generating Module and/or Power Park Module resulting in a change of level in the Output Usable of that Generating Unit and/or Power-Generating Module and/or Power Park Module below or above its previously notified availability, which is expected to last one Settlement Period or longer and up to three years ahead; or

b) an Interconnector Owner referred to in OC2.3.1(e) experiences any unplanned change to the availability of an External Interconnection Circuit or makes a future plan which would impact the availability of an External Interconnection Circuit resulting in any change in the Output Usable of that External Interconnection Circuit below or above its previously notified availability, which is expected to last one Settlement Period or longer and up to three years ahead;

The Generator or Interconnector Owner shall provide The Company with the best estimate of the revised available Output Usable profile using one of The Company’s recommended platforms.
For Generators subject to EU Transparency Regulations the Generator shall provide the data within 1 hour of the unplanned change in availability occurring, and for a planned change to the availability, the Generator shall provide the data within 1 hour of planning the availability change in line with EU Transparency Regulations. For Generators not subject to EU Transparency Regulations the Generator shall provide the data within 24 hours of the unplanned change in availability occurring, and for a planned change to the availability, the Generator shall provide the data within 24 hours of planning the availability change.

For an unplanned change in availability, the Interconnector Owner shall provide the data within 1 hour of the unplanned change in availability occurring, and for a planned change to the availability, the Interconnector Owner shall provide the data within 1 hour of planning the availability change in line with EU Transparency Regulations.

If the Generator referred to in OC2.3.1(a) provides information relating to multi-shaft Generating Units then the detail of the individual shaft availability levels, that have been summed to produce the Output Usable should also be defined within 24 hours.

In the case of an External Interconnection Circuit, the details of the individual pole-capacity levels that have been summed to produce the Output Usable should also be defined within 24 hours.

The Company may, as appropriate, contact each Generator and each Interconnector Owner who has supplied information to seek clarification on their Output Usable submissions.

OC2.4.1.2
At a regular time interval, at least once per day (by 1600 hours) and up to every hour:

The Company will:

(i) having taken into account the information notified to it by Generators and Interconnector Owners via the process defined in OC2.4.1.2.1 and taking into account:

   (1) Demand forecasts and details of proposed use of Demand Control received under OC1, and an Operational Planning Margin requirement set by The Company (the “OPMR”),

   (2) National Electricity Transmission System constraints and outages,

   (3) Network Operator System constraints and outages, known to The Company, and

   (4) the Output Usable required, in its view, to meet daily total MW requirements,

Provide each Generator and each Interconnector Owner (where required by The Company) in writing with any suggested amendments to the provisional Output Usable supplied by the Generator and Interconnector Owner which The Company believes necessary, and will advise Generators with Large Power Stations of the Surpluses for the National Electricity Transmission System and potential export limitations, which would occur without such amendments;

(ii) calculate and submit to BMRA:

1. total generating Output Usable from Generating Units assumed to be available to the Total System (National Output Usable);

2. generating Output Usable by fuel type from Generating Units assumed to be available to the Total System (Output Usable by fuel type);

3. generating Output Usable by individual Generating Units assumed to be available to the Total System (Output Usable by Generating Unit);

4. total Generating Plant Demand Margin assumed to be available to the Total System (National Margin);

5. total Generating Surplus assumed to be available to the Total System (National Surplus);

with daily resolution, for at least the peak Demand of each day for 2 day-ahead to 14 day-ahead time scope, and
with weekly resolution, for at least peak Demand of each week for 2 week-ahead up to 3 year-ahead time scope.

The calculation under (ii) will effectively define the envelope of opportunity for outages of Power Generating Modules (including DC Connected Power Park Modules), Synchronous Generating Units and Power Park Modules covering both Embedded and directly connected Large Power Stations.

The Company may, as appropriate, contact each Generator and each Interconnector Owner who has supplied information to seek clarification on outages and suggest amendments.

(iii) Where a Generator or Interconnector Owner or a Network Operator is unhappy with the suggested amendments to its provisional outage programme (in the case of a Generator or Interconnector Owner) or such potential outages (in the case of a Network Operator) it may contact The Company to explain its concerns and The Company and that Generator, Interconnector Owner or Network Operator will then discuss the problem and seek to resolve it.

(iv) The possible resolution of the problem may require The Company or a User to contact other Generators, Interconnector Owner or Network Operators, and joint meetings of all parties may, if any User feels it would be helpful, be convened by The Company. The need for further discussions, be they on the telephone or at meetings, can only be determined at the time.

Each Generator will provide The Company with updated Output Usable as per OC2.4.1 resulting from the above for Generating Unit, Power Generating Module and Power Part Module outage programme covering both Embedded and non-Embedded Large Power Stations.

The Company will then consider the updated Output Usable and takes this into account in the next calculation and submission to BMRA.

OC2.4.1.2.3 The Company retains the right to contact Generators with Large Power Stations, Interconnector Owners and Network Operators in reference to planned outages of their assets in timescales beyond the European Requirements (3 years) up to the 5 year ahead period to assist in the operational planning of National Electricity Transmission System outages.

OC2.4.1.3 Planning of National Electricity Transmission System Outages

OC2.4.1.3.1 Operational Planning Phase - Planning for Financial Years 2 to 5 inclusive ahead

The Company shall plan National Electricity Transmission System outages required in Years 2 to 5 inclusive required as a result of construction or refurbishment works. This contrasts with the planning of National Electricity Transmission System outages required in Years 0 and 1 ahead, when The Company also takes into account National Electricity Transmission System outages required as a result of maintenance.
Users should bear in mind that The Company will be planning the National Electricity Transmission System outage programme on the basis of the previous year's Final Generation Outage Programme and if in the event a Generator's, an Interconnector Owner's or Network Operator's outages differ from those contained in the Final Generation Outage Programme, or in the case of Network Operators, those known to The Company, in any way conflict with the National Electricity Transmission System outage programme, The Company need not alter the National Electricity Transmission System outage programme.

OC2.4.1.3.2 In each calendar year:

(a) By the end of week 8

Each Network Operator will notify The Company in writing of details of proposed outages in Years 2-5 ahead in its User System which may affect the performance of the Total System (which includes but is not limited to outages of User System Apparatus at Grid Supply Points and outages which constrain the output of Power Generating Modules (including DC Connected Power Park Modules) and/or Synchronous Generating Units and/or Power Park Modules Embedded within that User System).

Each Network Operator will notify The Company in writing of details of proposed outages in Years 2-5 ahead in its User System which may affect the declared values of Maximum Export Capacity and/or Maximum Import Capacity for each Interface Point within its User System together with the Network Operator's revised best estimate of the Maximum Export Capacity and/or Maximum Import Capacity during such outages. Network Operators will also notify The Company of any automatic and/or manual post fault actions that it intends to utilise or plans to utilise during such outages.

(b) By the end of week 13

Each Generator will inform The Company in writing of proposed outages in Years 2 - 5 ahead of Generator owned Apparatus (eg. busbar selectors) other than Power Generating Modules (including DC Connected Power Park Modules) and/or Synchronous Generating Units, and/or Power Park Modules, at each Grid Entry Point.

The Company will provide to each Network Operator and to each Generator and each Interconnector Owner, a copy of the information given to The Company under paragraph (a) above (other than the information given by that Network Operator). In relation to a Network Operator, the data must only be used by that User in planning and operating that Network Operator's User System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

(c) By the end of week 28

The Company will provide each Network Operator in writing with details of proposed outages in Years 2-5 ahead which may, in The Company's reasonable judgement, affect the performance of that Network Operator's User System.

(d) By the end of week 30

Where The Company or a Network Operator is unhappy with the proposed outages notified to it under (a), (b) or (c) above, as the case may be, equivalent provisions to those set out in OC2.4.1.2.2(iii) and (iv) will apply.
(e) **By the end of week 34**

*The Company* will draw up a draft *National Electricity Transmission System* outage plan covering the period Years 2 to 5 ahead and *The Company* will notify each *Generator*, *Interconnector Owner* and *Network Operator* in writing of those aspects of the plan which may operationally affect such *Generator* (other than those aspects which may operationally affect *Embedded Small Power Stations* or *Embedded Medium Power Stations*), *Interconnector Owner* or *Network Operator*. *The Company* will also indicate where a need may exist to issue other operational instructions or notifications (including but not limited to the requirement for the arming of an *Operational Intertripping* scheme) or *Emergency Instructions* to *Users* in accordance with BC2 to allow the security of the *National Electricity Transmission System* to be maintained within the *Licence Standards*.

**OC2.4.1.3.3** Operational Planning Phase - Planning for Financial Year 1 ahead

Each calendar year, *The Company* shall update the draft *National Electricity Transmission System* outage plan prepared under OC2.4.1.3.2 above and shall in addition take into account outages required as a result of maintenance work.

In each calendar year:

(a) **By the end of week 13**

*Generators* and *Non-Embedded Customers* will inform *The Company* in writing of proposed outages for Year 1 of *Generator* owned *Apparatus* at each *Grid Entry Point* (e.g. busbar selectors) other than *Power Generating Modules* (including *DC Connected Power Park Modules*), *Synchronous Generating Units* and/or *Power Park Modules* or *Non-Embedded Customer* owned *Apparatus*, as the case may be, at each *Grid Supply Point*.

(b) **By the end of week 28**

*The Company* will provide each *Network Operator* and each *Non-Embedded Customer* in writing with details of proposed outages in Year 1 ahead which may, in *The Company*’s reasonable judgement, affect the performance of its *User System* or the *Non-Embedded Customer Apparatus* at the *Grid Supply Point*.

(c) **By the end of week 32**

Each *Network Operator* will notify *The Company* in writing with details of proposed outages in Year 1 in its *User System* which may affect the performance of the *Total System* (which includes but is not limited to outages of *User System Apparatus* at *Grid Supply Points* and outages which constrain the output of *Power Generating Modules* (including *DC Connected Power Park Modules*), *Synchronous Generating Units* and/or *Power Park Modules Embedded within that User System*).

Each *Network Operator* will notify *The Company* in writing of details of proposed outages in Year 1 in its *User System* which may affect the declared values of *Maximum Export Capacity* and/or *Maximum Import Capacity* for each *Interface Point* within its *User System* together with the *Network Operator’s* revised best estimate of the *Maximum Export Capacity* and/or *Maximum Import Capacity* during such outages. *Network Operators* will also notify *The Company* of any automatic and/or manual post fault actions that it intends to utilise or plans to utilise during such outages.

Each *Network Operator* will also notify *The Company* in writing of any revisions to *Interface Point Target Voltage/Power Factor* data submitted pursuant to PC.A.2.5.4.2.

(d) **Between the end of week 32 and the end of week 34**

*The Company* will draw up a revised *National Electricity Transmission System* outage plan (which for the avoidance of doubt includes *Transmission Apparatus* at the *Connection Points*).
(e) By the end of week 34

The Company will notify each Generator, Interconnector Owner, and Network Operator, in writing, of those aspects of the National Electricity Transmission System outage programme which may, in The Company’s reasonable opinion, operationally affect that Generator (other than those aspects which may operationally affect Embedded Small Power Stations or Embedded Medium Power Stations), Interconnector Owner, or Network Operator including in particular proposed start dates and end dates of relevant National Electricity Transmission System outages.

The Company will provide to each Network Operator and to each Generator and each Interconnector Owner a copy of the information given to The Company under paragraph (c) above (other than the information given by that Network Operator). In relation to a Network Operator, the data must only be used by that User in planning and operating that Network Operator’s User System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

(f) By the end of week 36

Where a Generator, Interconnector Owner or Network Operator is unhappy with the proposed aspects notified to it under (e) above, equivalent provisions to those set out in OC2.4.1.2.2(iii) and (iv) will apply.

(g) Between the end of week 34 and 49

The Company will draw up a final National Electricity Transmission System outage plan covering Year 1.

(h) By the end of week 49

(i) The Company will complete the final National Electricity Transmission System outage plan for Year 1. The plan for Year 1 becomes the final plan for Year 0 when by expiry of time Year 1 becomes Year 0.

(ii) The Company will notify each Generator, each Interconnector Owner and each Network Operator in writing of those aspects of the plan which may operationally affect such Generator (other than those aspects which may operationally affect Embedded Small Power Stations or Embedded Medium Power Stations), Interconnector Owner or Network Operator including in particular proposed start dates and end dates of relevant National Electricity Transmission System outages. The Company will also indicate where a need may exist to issue other operational instructions or notifications (including but not limited to the requirement for the arming of an Operational Intertripping scheme) or Emergency Instructions to Users in accordance with BC2 to allow the security of the National Electricity Transmission System to be maintained within the Licence Standards. The Company will also inform each relevant Non-Embedded Customer of the aspects of the plan which may affect it.

(iii) In addition, in relation to the final National Electricity Transmission System outage plan for Year 1, The Company will provide to each Generator and each Interconnector Owner a copy of the final National Electricity Transmission System outage plan for that year. OC2.4.1.3.4 contains provisions whereby updates of the final National Electricity Transmission System outage plan are provided. The plan and the updates will be provided in writing. It should be noted that the final National Electricity Transmission System outage plan for Year 1 and the updates will not give a complete understanding of how the National Electricity Transmission System will operate in real time, where the National Electricity Transmission System operation may be affected by other factors which may not be known at the time of the plan and the updates. Therefore, Users should place no reliance on the plan or the updates showing a set of conditions which will actually arise in real time.
(i) Information Release Or Exchange

This paragraph (i) contains alternative requirements on The Company, paragraph (z) being an alternative to a combination of paragraphs (x) and (y). Paragraph (z) will only apply in relation to a particular User if The Company and that User agree that it should apply, in which case paragraphs (x) and (y) will not apply. In the absence of any relevant agreement between The Company and the User, The Company will only be required to comply with paragraphs (x) and (y).

Information Release To Each Network Operator And Non-Embedded Customer

Between the end of Week 34 and 49 The Company will upon written request:

(x) for radial systems, provide each Network Operator and Non Embedded Customer with data to allow the calculation by the Network Operator, and each Non Embedded Customer, of symmetrical and asymmetrical fault levels; and

(y) for interconnected Systems, provide to each Network Operator an equivalent network, sufficient to allow the identification of symmetrical and asymmetrical fault levels, and power flows across interconnecting User Systems directly connected to the National Electricity Transmission System; or

System Data Exchange

(z) as part of a process to facilitate understanding of the operation of the Total System,

(1) The Company will make available to each Network Operator, the National Electricity Transmission System Study Network Data Files covering Year 1 which are of relevance to that User's System;

(2) where The Company and a User have agreed to the use of data links between them, the making available will be by way of allowing the User access to take a copy of the National Electricity Transmission System Study Network Data Files once during that period. The User may, having taken that copy, refer to the copy as often as it wishes. Such access will be in a manner agreed by The Company and may be subject to separate agreements governing the manner of access. In the absence of agreement, the copy of the National Electricity Transmission System Study Network Data Files will be given to the User on a disc, or in hard copy, as determined by The Company;

(3) the data contained in the National Electricity Transmission System Study Network Data Files represents The Company's view of operating conditions although the actual conditions may be different;

(4) The Company will notify each Network Operator, as soon as reasonably practicable after it has updated the National Electricity Transmission System Study Network Data Files covering Year 1 that it has done so, when this update falls before the next annual update under this OC2.4.1.3.3(i). The Company will then make available to each Network Operator who has received an earlier version (and in respect of whom the agreement still exists), the updated National Electricity Transmission System Study Network Files covering the balance of Years 1 and 2 which remain given the passage of time, and which are of relevance to that User’s System. The provisions of paragraphs (2) and (3) above shall apply to the making available of these updates;

(5) the data from the National Electricity Transmission System Study Network Data Files received by each Network Operator must only be used by that User in planning and operating that Network Operator’s User System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

OC2.4.1.3.4 Operational Planning Phase - Planning In Financial Year 0 Down To The Programming Phase
(And In The Case Of Load Transfer Capability, Also During The Programming Phase)
(a) The National Electricity Transmission System outage plan for Year 1 issued under OC2.4.1.3.3 shall become the plan for Year 0 when by expiry of time Year 1 becomes Year 0.

(b) Each Generator or Interconnector Owner or Network Operator or Non-Embedded Customer may at any time during Year 0, request The Company in writing for changes to the outages requested by them under OC2.4.1.3.3. In relation to that part of Year 0, excluding the period 1-7 weeks from the date of request, The Company shall determine whether the changes are possible and shall notify the Generator, Interconnector Owner, Network Operator or Non-Embedded Customer in question whether this is the case as soon as possible, and in any event within 14 days of the date of receipt by The Company of the written request in question.

Where The Company determines that any change so requested is possible and notifies the relevant User accordingly, The Company will provide to each Network Operator, each Interconnector Owner, and each Generator a copy of the request to which The Company has agreed which relates to outages on Systems of Network Operators (other than any request made by that Network Operator). The information must only be used by that Network Operator in planning and operating that Network Operator’s User System and must not be used for any other purpose or passed on to, or used by, any other business of that User or to, or by, any person within any other such business or elsewhere.

(c) During Year 0 (including the Programming Phase) each Network Operator shall at The Company’s request, make available to The Company, such details of automatic and manual load transfer capability of:

(i) 12MW or more (averaged over any half hour) for England and Wales
(ii) 10MW or more (averaged over any half hour) for Scotland between Grid Supply Points.

During Year 0 (including the Programming Phase) each Network Operator shall notify The Company of any revisions to the information provided pursuant to OC2.4.1.3.3 (c) for Interface Points as soon as reasonably practicable after the Network Operator becomes aware of the need to make such revisions.

(d) When necessary during Year 0, The Company will notify each Generator, each Interconnector Owner and Network Operator and each Non-Embedded Customer, in writing of those aspects of the National Electricity Transmission System outage programme in the period from the 8th week ahead to the 52nd week ahead, which may, in The Company’s reasonable opinion, operationally affect that Generator (other than those aspects which may operationally affect Embedded Small Power Stations or Embedded Medium Power Stations) Interconnector Owner or Network Operator or Non-Embedded Customer including in particular proposed start dates and end dates of relevant National Electricity Transmission System outages.

The Company will also notify changes to information supplied by The Company pursuant to OC2.4.1.3.3(i)(x) and (y) except where in relation to a User information was supplied pursuant to OC2.4.1.3.3(i)(z). In that case:

(i) The Company will, by way of update of the information supplied by it pursuant to OC2.4.1.3.3(i)(z), make available at the first time in Year 0 that it updates the National Electricity Transmission System Study Network Data Files in respect of Year 0 (such update being an update on what was shown in respect of Year 1 which has then become Year 0) to each Network Operator who has received an earlier version under OC2.4.1.3.3(i)(z) (and in respect of whom the agreement still exists), the National Electricity Transmission System Study Network Data Files covering Year 0 which are of relevance to that User’s System.
(ii) **The Company** will notify each relevant **Network Operator**, as soon as reasonably practicable after it has updated the **National Electricity Transmission System Study Network Data Files** covering Year 0, that it has done so. **The Company** will then make available to each such **Network Operator**, the updated **National Electricity Transmission System Study Network Data Files** covering the balance of Year 0 which remains given the passage of time, and which are of relevance to that **User's System**.

(iii) The provisions of OC2.4.1.3.3(i)(z)(2), (3) and (5) shall apply to the provision of data under this part of OC2.4.1.3.4(d) as if set out in full.

**The Company** will also indicate where a need may exist to issue other operational instructions or notifications (including but not limited to the requirement for the arming of an **Operational Intertripping** scheme) or **Emergency Instructions** to **Users** in accordance with BC2 to allow the security of the **National Electricity Transmission System** to be maintained within the **Licence Standards**.

(e) In addition, by the end of each month during Year 0, **The Company** will provide to each **Generator** and each **Interconnector Owner** a notice containing any revisions to the final **National Electricity Transmission System** outage plan for Year 1, provided to the **Generator** or the **Interconnector Owner** under OC2.4.1.3.3 or previously under this provision, whichever is the more recent.
OC2.4.1.3.5 Programming Phase

(a) By 1600 hours each Thursday

(i) The Company shall continue to update a preliminary National Electricity Transmission System outage programme for the eighth week ahead, a provisional National Electricity Transmission System outage programme for the next week ahead and a final day ahead National Electricity Transmission System outage programme for the following day.

(ii) The Company will notify each Generator, Interconnector Owner and Network Operator and each Non-Embedded Customer, in writing of those aspects of the preliminary National Electricity Transmission System outage programme which may operationally affect each Generator (other than those aspects which may operationally affect Embedded Small Power Stations or Embedded Medium Power Stations) or Interconnector Owner or Network Operator and each Non-Embedded Customer including in particular proposed start dates and end dates of relevant National Electricity Transmission System outages.

The Company will also notify changes to information supplied by The Company pursuant to OC2.4.1.3.3(i)(x) and (y) except where in relation to a User information was supplied pursuant to OC2.4.1.3.3(i)(z). In that case:

(1) The Company will, by way of update of the information supplied by it pursuant to OC2.4.1.3.3(i)(z), make available the National Electricity Transmission System Study Network Data Files for the next week ahead and

(2) The Company will notify each relevant Network Operator, as soon as reasonably practicable after it has updated the National Electricity Transmission System Study Network Data Files covering the next week ahead that it has done so, and

(3) The provisions of OC2.4.1.3.3(i)(z)(2), (3) and (5) shall apply to the provision of data under this part of OC2.4.1.3.5(a)(ii) as if set out in full.

The Company may make available, the National Electricity Transmission System Study Network Data Files for the next week ahead where The Company and a particular User agree, and in such case the provisions of OC2.4.1.3.3(i)(x) and (y) and the provisions of OC2.4.1.3.4(d) and OC2.4.1.3.5(a) which relate to OC2.4.1.3.3(i)(x) and (y) shall not apply. In such case, the provisions of this OC2.4.1.3.5(a)(ii)2 and 3 shall apply to the provision of the data under this part of OC2.4.1.3.5(a)(ii) as if set out in full.

The Company will also indicate where a need may exist to arm an Operational Intertripping scheme, emergency switching, emergency Demand management or other measures including the issuing of other operational instructions or notifications or Emergency Instructions to Users in accordance with BC2 to allow the security of the National Electricity Transmission System to be maintained within the Licence Standards.

(b) By 1000 hours each Friday

Generators, Interconnector Owners and Network Operators will discuss with The Company and confirm in writing to The Company, acceptance or otherwise of the requirements detailed under OC2.4.1.3.5.

Network Operators shall confirm for the following week:

(i) the details of any outages of its User System that will restrict the Maximum Export Capacity and/or Maximum Import Capacity at any Interface Points within its User System for the following week; and

(ii) any changes to the previously declared values of the Interface Point Target Voltage/Power Factor.
(c) **By 1600 hours each Friday**

(i) The **Company** shall finalise the preliminary **National Electricity Transmission System** outage programme up to the seventh week ahead. The **Company** will endeavour to give as much notice as possible to a **Generator** with nuclear **Large Power Stations** which may be operationally affected by an outage which is to be included in such programme.

(ii) The **Company** shall finalise the provisional **National Electricity Transmission System** outage programme for the next week ahead.

(iii) The **Company** shall finalise the **National Electricity Transmission System** outage programme for the weekend through to the next normal working day.

(iv) In each case, The **Company** will indicate the factors set out in (a)(ii) above (other than those aspects which may operationally affect **Embedded Small Power Stations** or **Embedded Medium Power Stations**) to the relevant **Generators** and **Network Operators** and **Non-Embedded Customers**.

(v) Where a **Generator** with nuclear **Large Power Stations** which may be operationally affected by the preliminary **National Electricity Transmission System** outage programme referred to in (i) above (acting as a reasonable operator) is concerned on grounds relating to safety about the effect which an outage within such outage programme might have on one or more of its nuclear **Large Power Stations**, it may contact The **Company** to explain its concerns and discuss whether there is an alternative way of taking that outage (having regard to technical feasibility). If there is such an alternative way, but The **Company** refuses to adopt that alternative way in taking that outage, that **Generator** may involve the **Disputes Resolution Procedure** to decide on the way the outage should be taken. If there is no such alternative way, then The **Company** may take the outage despite that **Generator's** concerns.

(d) **By 1600 hours each Monday, Tuesday, Wednesday and Thursday**

(i) The **Company** shall prepare a final **National Electricity Transmission System** outage programme for the following day.

(ii) The **Company** shall notify each **Generator** and **Network Operator** and **Non-Embedded Customer** in writing of the factors set out in (a)(ii) above (other than those aspects which may operationally affect **Embedded Small Power Stations** or **Embedded Medium Power Stations**).

**OC2.4.2 DATA REQUIREMENTS**

**OC2.4.2.1** When a **Statement of Readiness** under the **Bilateral Agreement** and/or **Construction Agreement** is submitted, and thereafter in calendar week 24 in each calendar year,

(a) each **Generator** shall (subject to OC2.4.2.1(k)) in respect of each of its:-

(i) **Gensets** (in the case of the **Generation Planning Parameters**); and

(ii) **CCGT Units** within each of its **CCGT Modules** at a **Large Power Station** (in the case of the **Generator Performance Chart**)

(iii) **Generating Units** within each of its **Synchronous Power Generating Modules** at a **Large Power Station** (in the case of the **Power-Generating Module Performance Chart** and **Synchronous Generating Unit Performance Chart**)

submit to The **Company** in writing the **Generation Planning Parameters** and the **Generator Performance Charts** as required.

(b) Each shall meet the requirements of CC.6.3.2 or ECC.6.3.2 (as applicable) and shall reasonably reflect the true operating characteristics of the **Genset**.
(c) They shall be applied (unless revised under this OC2 or (in the case of the Generator Performance Chart only) BC1 in relation to Other Relevant Data) from the Completion Date, in the case of the ones submitted with the Statement of Readiness, and in the case of the ones submitted in calendar week 24, from the beginning of week 25 onwards.

(d) They shall be in the format indicated in Appendix 1 for these charts and as set out in Appendix 2 for the Generation Planning Parameters.

(e) Any changes to the Generator Performance Chart or Generation Planning Parameters should be notified to The Company promptly.

(f) Generators should note that amendments to the composition of the Power Generating Module, CCGT Module or Power Park Module at Large Power Stations may only be made in accordance with the principles set out in PC.A.3.2.3 or PC.A.3.2.4 respectively. If in accordance with PC.A.3.2.3 or PC.A.3.2.4 an amendment is made, any consequential changes to the Generation Planning Parameters should be notified to The Company promptly.

(g) The Generator Performance Chart must be as described below and demonstrate the limitation on reactive capability of the System voltage at 3% above nominal. It must also include any limitations on output due to the prime mover (both maximum and minimum), Generating Unit step up transformer or User System.

   i. For a Synchronous Generating Unit on a Generating Unit specific basis at the Generating Unit stator terminals. It must include details of the Generating Unit transformer parameters.

   ii. For a Non-Synchronous Generating Unit (excluding a Power Park Unit) on a Generating Unit specific basis at the Grid Entry Point (or User System Entry Point if Embedded).

   iii. For a Power Park Module, on a Power Park Module specific basis at the Grid Entry Point (or User System Entry Point if Embedded).

   iv. For a DC Converter on a DC Converter specific basis at the Grid Entry Point (or User System Entry Point if Embedded).

   v. For a Synchronous Generating Unit within a Synchronous Power Generating Module, both the Power-Generating Module Performance Chart and Synchronous Generating Unit Performance Chart should be provided.

(h) For each CCGT Unit, and any other Generating Unit or Power Park Module or Power Generating Module whose performance varies significantly with ambient temperature, the Generator Performance Chart (including the Power-Generating Module Performance Chart and Synchronous Generating Unit Performance Chart in the case of Synchronous Power Generating Modules) shall show curves for at least two values of ambient temperature so that The Company can assess the variation in performance over all likely ambient temperatures by a process of linear interpolation or extrapolation. One of these curves shall be for the ambient temperature at which the Generating Unit’s output, or CCGT Module or Power-Generating Module at a Large Power Station output or Power Park Module’s output, as appropriate, equals its Registered Capacity.

(i) The Generation Planning Parameters supplied under OC2.4.2.1 shall be used by The Company for operational planning purposes only and not in connection with the operation of the Balancing Mechanism (subject as otherwise permitted in the BC).
(j) Each Generator shall in respect of each of its Synchronous Power Generating Modules or CCGT Modules (including those which are part of a Synchronous Power Generating Module) at Large Power Stations submit to The Company in writing a CCGT Module Planning Matrix and/or a Synchronous Power-Generating Module Planning Matrix. It shall be prepared on a best estimate basis relating to how it is anticipated the Synchronous Power-Generating Module or CCGT Module will be running and which shall reasonably reflect the true operating characteristics of the Power-Generating Module or CCGT Module. It will be applied (unless revised under this OC2) from the Completion Date, in the case of the one submitted with the Statement of Readiness, and in the case of the one submitted in calendar week 24, from the beginning of week 31 onwards. It must show the combination of CCGT Units or Synchronous Power Generating Units which would be running in relation to any given MW output, in the format indicated in Appendix 3.

Any changes must be notified to The Company promptly. Generators should note that amendments to the composition of the CCGT Module or Synchronous Power-Generating Module at Large Power Stations may only be made in accordance with the principles set out in PC.A.3.2.3. If in accordance with PC.A.3.2.3 an amendment is made, an updated CCGT Module Planning Matrix or Synchronous Power-Generating Module Planning Matrix must be immediately submitted to The Company in accordance with this OC2.4.2.1(b).

The CCGT Module Planning Matrix or Synchronous Power-Generating Module Planning Matrix will be used by The Company for operational planning purposes only and not in connection with the operation of the Balancing Mechanism.

(k) Each Generator shall in respect of each of its Cascade Hydro Schemes also submit the Generation Planning Parameters detailed at OC2.A.2.6 to OC2.A.2.10 for each Cascade Hydro Scheme. Such parameters need not also be submitted for the individual Gensets within such Cascade Hydro Scheme.

(l) Each Generator shall in respect of each of its Power Park Modules at Large Power Stations submit to The Company in writing a Power Park Module Planning Matrix. It shall be prepared on a best estimate basis relating to how it is anticipated the Power Park Module will be running and which shall reasonably reflect the operating characteristics of the Power Park Module and the BM Unit of which it forms part. It will be applied (unless revised under this OC2) from the Completion Date, in the case of the one submitted with the Statement of Readiness, and in the case of the one submitted in calendar week 24, from the beginning of week 31 onwards. It must show the number of each type of Power Park Unit in the Power Park Module typically expected to be available to generate and the BM Unit of which it forms part, in the format indicated in Appendix 4. The Power Park Module Planning Matrix shall be accompanied by a graph showing the variation in MW output with Intermittent Power Source (e.g. MW vs wind speed) for the Power Park Module. The graph shall indicate the typical value of the Intermittent Power Source for the Power Park Module.

Any changes must be notified to The Company promptly. Generators should note that amendments to the composition of the Power Park Module at Large Power Stations may only be made in accordance with the principles set out in PC.A.3.2.4. If in accordance with PC.A.3.2.4 an amendment is made, an updated Power Park Module Planning Matrix must be immediately submitted to The Company in accordance with this OC2.4.2.1(a).

The Power Park Module Planning Matrix will be used by The Company for operational planning purposes only and not in connection with the operation of the Balancing Mechanism.
(m) For each Synchronous Generating Unit (including Synchronous Generating Units within a Power Generating Module) where the Generator intends to adjust the Generating Unit terminal voltage in response to a MVAr output Instruction or a Target Voltage Level instruction in accordance with BC2.A.2.6 the Generator Performance Chart including the Synchronous Generating Unit Performance Chart shall show curves corresponding to the Generating Unit terminal voltage being controlled to its rated value and to its maximum value.

OC2.4.2.2 Each Network Operator shall by 1000 hrs on the day falling seven days before each Operational Day inform The Company in writing of any changes to the circuit details called for in PC.A.2.2.1 which it is anticipated will apply on that Operational Day (under BC1 revisions can be made to this data).

OC2.4.2.3 Under Retained EU Law (Commission Regulation (EU) 543/2013), Users are required to submit certain data to the Data Publisher for publication. The Company is required to facilitate the collection, verification and processing of data from Users for onward transmission to the Data Publisher.

Each Generator and each Non-Embedded Customer connected to or using the National Electricity Transmission System shall provide The Company with such information as required by and set out in DRC Schedule 6 (Users’ Outage Data EU Transparency Availability Data) in the timescales detailed therein.

OC2.4.3 NEGATIVE RESERVE ACTIVE POWER MARGINS

OC2.4.3.1 At a regular time interval, at least once each day (by 1600 hours) and up to every hour The Company will, taking into account the Generation Outage Programme and forecast of Output Usable supplied by each Generator and by each Interconnector Owner defined in OC2.4.1.2.1 and forecast Demand for the minimum Demand period, calculate and publish:-

1. the level of the System NRAPM each day within the period 2 to 14 days ahead (inclusive) and for each week the level of risk of System NRAPM within the 2-52 week ahead period; and

2. the level of the Localised NRAPM (currently for the main constraint between England and Scotland only) for each day within the period 2 to 14 days ahead (inclusive) having taken into account the appropriate limit on transfers to and from the System Constraint Group and for each week the level of risk of Localised NRAPM within the 2-52 week ahead period.

Outages Adjustments

(a) Under the necessary circumstances The Company will then contact Generators in respect of their Large Power Stations and Interconnector Owners to discuss outages as set out in the following paragraphs of this OC2.4.3.1.

(b) The Company will contact all Generators and Interconnector Owners in the case of low System NRAPM and will contact Generators in relation to relevant Large Power Stations and Interconnector Owners in the case of low Localised NRAPM. The Company will raise with each Generator and Interconnector Owner the problems it is anticipating due to the low System NRAPM or Localised NRAPM and will discuss:

1. whether any change is possible to the estimate of Genset inflexibility; and

2. whether Genset or External Interconnection outages can be taken to coincide with the periods of low System NRAPM or Localised NRAPM (as the case may be).

In relation to Generators with nuclear Large Power Stations the discussions on outages can include the issue of whether outages can be taken for re-fuelling purposes to coincide with the relevant low System NRAPM and/or Localised NRAPM periods.
(c) If agreement is reached with a Generator or an Interconnector Owner, then such Generator or Interconnector Owner will take such outage, as agreed with The Company, and the Generator or an Interconnector Owner will issue updates to its Output Usable via the data provision process defined in OC2.4.1.2.1 and The Company will process the updated data which will then be included in the next published update of the System NRAPM and/or Localised NRAPM.

(d) If on the day prior to an Operational Day, it is apparent from the BM Unit Data submitted by Users under BC1 that System NRAPM and/or Localised NRAPM (as the case may be) is, in The Company's reasonable opinion, too low, then in accordance with the procedures and requirements set out in BC1.5.5 The Company may contact Users to discuss whether changes to Physical Notifications are possible, and if they are, will reflect those in the operational plans for the next following Operational Day or will, in accordance with BC2.9.4 instruct Generators to De-Synchronise a specified Genset for such period. In determining which Genset to so instruct, BC2 provides that The Company will not (other than as referred to below) consider in such determination (and accordingly shall not instruct to De-Synchronise) any Genset within an Existing Gas Cooled Reactor Plant. BC2 further provides that:-

(i) The Company is permitted to instruct to De-Synchronise any Gensets within an Existing AGR Plant if those Gensets within an Existing AGR Plant have failed to offer to be flexible for the relevant instance at the request of The Company provided the request is within the Existing AGR Plant Flexibility Limit.

(ii) The Company will only instruct to De-Synchronise any Gensets within an Existing Magnox Reactor Plant or within an Existing AGR Plant (other than under (i) above) if the level of System NRAPM (taken together with System constraints) and/or Localised NRAPM is such that it is not possible to avoid De-Synchronising such Generating Unit or Power Generating Module, and provided the power flow across each External Interconnection is either at zero or results in an export of power from the Total System. This proviso applies in all cases in the case of System NRAPM and in the case of Localised NRAPM, only when the power flow would have a relevant effect.

OC2.4.4 FREQUENCY SENSITIVE OPERATION

By 1600 hours each Wednesday

OC2.4.4.1 Using such information as The Company shall consider relevant including, if appropriate, forecast Demand, any estimates provided by Generators of Genset inflexibility and anticipated plant mix relating to operation in Frequency Sensitive Mode, The Company shall determine for the period 2 to 7 weeks ahead (inclusive) whether it is possible that there will be insufficient Gensets (other than those Gensets within Existing Gas Cooled Reactor Plant which are permitted to operate in Limited Frequency Sensitive Mode at all times under BC3.5.3) to operate in Frequency Sensitive Mode for all or any part of that period.

OC2.4.4.2 BC3.5.3 explains that The Company permits Existing Gas Cooled Reactor Plant other than Frequency Sensitive AGR Units to operate in a Limited Frequency Sensitive Mode at all times.

OC2.4.4.3 If The Company foresees that there will be an insufficiency in Gensets operating in a Frequency Sensitive Mode, it will contact Generators in order to seek to agree (as soon as reasonably practicable) that all or some of the Gensets (the MW amount being determined by The Company but the Gensets involved being determined by the Generator) will take outages to coincide with such period as The Company shall specify to enable replacement by other Gensets which can operate in a Frequency Sensitive Mode. If agreement is reached (which unlike the remainder of OC2 will constitute a binding agreement) then such Generator will take such outage as agreed with The Company. If agreement is not reached, then the provisions of BC2.9.5 may apply.
If in *The Company*'s reasonable opinion it is necessary for both the procedure set out in OC2.4.3 (relating to System NRAPM and Localised NRAPM) and in OC2.4.4 (relating to operation in Frequency Sensitive Mode) to be followed in any given situation, the procedure set out in OC2.4.3 will be followed first, and then the procedure set out in OC2.4.4. For the avoidance of doubt, nothing in this paragraph shall prevent either procedure from being followed separately and independently of the other.

**OPERATING MARGIN DATA REQUIREMENTS**

**OC2.4.6.1 Modifications to relay settings**

‘Relay settings’ in this OC2.4.6.1 refers to the settings of Low Frequency Relays in respect of Gensets that are available for start from standby by Low Frequency Relay initiation with Fast Start Capability agreed pursuant to the Bilateral Agreement.

By 1600 hours each Wednesday

A change in relay settings will be sent by *The Company* no later than 1600 hours on a Wednesday to apply from 1000 hours on the Monday following. The settings allocated to particular Large Power Stations may be interchanged between 49.70Hz and 49.60Hz (or such other System Frequencies as *The Company* may have specified) provided the overall capacity at each setting and System requirements can, in *The Company*'s view, be met.

Between 1600 hours each Wednesday and 1200 hours each Friday

If a Generator wishes to discuss or interchange settings it should contact *The Company* by 1200 hours on the Friday prior to the Monday on which it would like to institute the changes to seek *The Company*'s agreement. If *The Company* agrees, *The Company* will then send confirmation of the agreed new settings.

By 1500 hours each Friday

If any alterations to relay settings have been agreed, then the updated version of the current relay settings will be sent to affected Users by 1500 hours on the Friday prior to the Monday on which the changes will take effect. Once accepted, each Generator (if that Large Power Station is not subject to forced outage or Planned Outage) will abide by the terms of its latest relay settings.

In addition, *The Company* will take account of any Large Power Station unavailability (as notified under OC2.4.1.2 submissions) in its total Operating Reserve policy.

*The Company* may from time to time, for confirmation purposes only, issue the latest version of the current relay settings to each affected Generator.

**OC2.4.6.2 Operational Planning Margin Requirements (OPMR)**

At a regular time interval, at least once each day (by 1600 hours) and up to every hour

*The Company* will provide an indication of the level of Operating Reserve to be utilised by *The Company* in connection with the operation of the Balancing Mechanism covering a 2-14 day ahead period (with a daily peak demand resolution) and the 2-52 week resolution (with a weekly resolution focusing on the peak demand of the week). This level shall be purely indicative.

This Operational Planning Margin requirements indication will also note the possible level of High Frequency Response to be utilised by *The Company* in connection with the operation of the Balancing Mechanism in the week beginning with the Operational Day commencing during the subsequent Monday, which level shall be purely indicative.

**OC2.4.7 In the event that:**
a) a Non-Embedded Customer experiences the planned unavailability of its Apparatus resulting in the reduction of Demand of 100MW or more, or a change to the planned unavailability of its Apparatus resulting in a change in Demand of 100MW or more, for one Settlement Period or longer; or

b) a Non-Embedded Customer experiences a change in the actual availability of its Apparatus resulting in a change in Demand of 100MW or greater; or

c) a Generator experiences a planned unavailability of a Generating Unit and/or Power-Generating Module resulting in a change of 100MW or more in the Output Usable of that Generating Unit and/or Power-Generating Module below its previously notified availability, which is expected to last one Settlement Period or longer and up to three years ahead; or

d) a Generator experiences a change of 100MW or more in the Maximum Export Limit of a Generating Unit which is expected to last one Settlement Period or longer; or

e) a Generator experiences a planned unavailability resulting in a change of 100MW or more in its aggregated Output Usable below its previously notified availability for a Power Station with a Registered Capacity of 200MW or more and which is expected to last one Settlement Period or longer and up to three years ahead, save where data has been provided pursuant to OC.2.4.7(c) above; or

f) a Generator experiences a change of 100MW or more in the aggregated Maximum Export Limit of a Power Station with a Registered Capacity of 200MW or more, which is expected to last one Settlement Period or longer, save where data has been provided pursuant to OC.2.4.7(d) above;

such Non-Embedded Customer or Generator shall provide The Company with the EU Transparency Availability Data in accordance with DRC Schedule 6 (Users’ Outage Data) using MODIS and, with reference to points OC2.4.7(a) to (f), Retained EU Law (Commission Regulation (EU) 543/2013) articles 7.1(a), 7.1(b), 15.1(a), 15.1(b), 15.1(c) and 15.1(d).

**OC2.4.8** The Company will for each day publish the actual largest secured loss of generation (i.e. 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 External Interconnections for each settlement period on The Company’s website.
POWER PARK MODULE PERFORMANCE CHART AT THE CONNECTION POINT OR USER’S SYSTEM ENTRY POINT

LEADING

Point A is equivalent (in MVAr) to: 0.95 leading Power Factor at Rated MW output
Point B is equivalent (in MVAr) to: 0.95 lagging Power Factor at Rated MW output
Point C is equivalent (in MVAr) to: -5% of Rated MW output
Point D is equivalent (in MVAr) to: +5% of Rated MW output
Point E is equivalent (in MVAr) to: -12% of Rated MW output
Line F is equivalent (in MVAr) to: Leading Power Factor Reactive Despatch Network Restriction
Line G is equivalent (in MVAr) to: Lagging Power Factor Reactive Despatch Network Restriction

LAGGING

Where a Reactive Despatch Network Restriction is in place which requires following of local voltage conditions, alternatively to Line F and G, please check this box.
APPENDIX 2 - GENERATION PLANNING PARAMETERS

OC2.A.2  Generation Planning Parameters
The following parameters are required in respect of each Genset.

OC2.A.2.1  Regime Unavailability
Where applicable the following information must be recorded for each Genset.
- Earliest synchronising time:
  - Monday
  - Tuesday to Friday
  - Saturday to Sunday
- Latest de-synchronising time:
  - Monday to Thursday
  - Friday
  - Saturday to Sunday

OC2.A.2.2  Synchronising Intervals
(a) The synchronising interval between Gensets in a Synchronising Group assuming all Gensets have been Shutdown for 48 hours;
(b) The Synchronising Group within the Power Station to which each Genset should be allocated.

OC2.A.2.3  De-Synchronising Interval
A fixed value De-Synchronising interval between Gensets within a Synchronising Group.

OC2.A.2.4  Synchronising Generation
The amount of MW produced at the moment of Synchronising assuming the Genset has been Shutdown for 48 hours.

OC2.A.2.5  Minimum Non-zero time (MNZT)
The minimum period on-load between Synchronising and De-Synchronising assuming the Genset has been Shutdown for 48 hours.

OC2.A.2.6  Run-Up rates
A run-up characteristic consisting of up to three stages from Synchronising Generation to Output Usable with up to two intervening break points assuming the Genset has been Shutdown for 48 hours.

OC2.A.2.7  Run-down rates
A run down characteristic consisting of up to three stages from Output Usable to De-Synchronising with breakpoints at up to two intermediate load levels.
OC2.A.2.8 Notice to Deviate from Zero (NDZ)
The period of time normally required to Synchronise a Genset following instruction from The Company assuming the Genset has been Shutdown for 48 hours.

OC2.A.2.9 Minimum Zero time (MZT)
The minimum interval between De-Synchronising and Synchronising a Genset.

OC2.A.2.10 Not used.

OC2.A.2.11 Gas Turbine Units loading parameters
- Loading rate for fast starting
- Loading rate for slow starting
APPENDIX 3 - CCGT MODULE PLANNING MATRIX

CCGT Module Planning Matrix Example Form

<table>
<thead>
<tr>
<th>CCGT MODULE</th>
<th>CCGT GENERATING UNITS AVAILABLE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1st GT</td>
</tr>
<tr>
<td>OUTPUT USABLE MW</td>
<td></td>
</tr>
<tr>
<td>0MW to 150MW</td>
<td>/</td>
</tr>
<tr>
<td>151MW to 250MW</td>
<td>/</td>
</tr>
<tr>
<td>251MW to 300MW</td>
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</tr>
<tr>
<td>301MW to 400MW</td>
<td>/</td>
</tr>
<tr>
<td>401MW to 450MW</td>
<td>/</td>
</tr>
<tr>
<td>451MW to 550MW</td>
<td>/</td>
</tr>
</tbody>
</table>
## APPENDIX 4 - POWER PARK MODULE PLANNING MATRIX

Power Park Module Planning Matrix Example Form

<table>
<thead>
<tr>
<th>BM Unit Name</th>
<th>Power Park Module [unique identifier]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>POWER PARK UNIT AVAILABILITY</th>
<th>POWER PARK UNITS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description (Make/Model)</td>
<td>Type A</td>
</tr>
<tr>
<td>Number of units</td>
<td></td>
</tr>
</tbody>
</table>

The **Power Park Module Planning 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**.
## SYNCHRONOUS POWER GENERATING MODULE PLANNING MATRIX

### Synchronous Power Generating Module Planning Matrix Example Form

<table>
<thead>
<tr>
<th>SYNCHRONOUS POWER GENERATING MODULE</th>
<th>SYNCHRONOUS POWER GENERATING UNITS AVAILABLE</th>
<th>OUTPUT USABLE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1st GT</td>
<td>2nd GT</td>
</tr>
<tr>
<td><strong>OUTPUT USABLE MW</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>0MW to 150MW</td>
<td>150</td>
<td>150</td>
</tr>
<tr>
<td>151MW to 250MW</td>
<td>/</td>
<td>/</td>
</tr>
<tr>
<td>251MW to 300MW</td>
<td>/</td>
<td>/</td>
</tr>
<tr>
<td>301MW to 400MW</td>
<td>/</td>
<td>/</td>
</tr>
<tr>
<td>401MW to 450MW</td>
<td>/</td>
<td>/</td>
</tr>
<tr>
<td>451MW to 550MW</td>
<td>/</td>
<td>/</td>
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</tbody>
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< END OF OPERATING CODE NO. 2 >
OPERATING CODE NO. 3  
(OC3)  
SYSTEM INCIDENTS REPORT  
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OC3.1 INTRODUCTION
Operating Code No.3 (“OC3”) is concerned with the monthly publication by The Company of an incident report and Frequency data for the National Electricity Transmission System.

OC3.2 OBJECTIVE
The objective of OC3 is for The Company to produce a monthly report of incidents and frequency data. The report and data are important to industry and the Grid Code Review Panel as they help monitor the effectiveness of the technical requirements in the Grid Code and Distribution Code.

OC3.3 SCOPE
OC3 applies to The Company.

OC3.4 SYSTEM INCIDENTS REPORT
The Company shall prepare and submit to the Grid Code Review Panel monthly a report titled the System Incidents Report, which shall contain:

(a) a record of each and all of any of the following Events, defined as Significant Events, on the National Electricity Transmission System:

(i) a loss of infeed or exfeed (import or export including generation, Demand and interconnection) of =>250MW;

(ii) a Frequency excursion outside the limits 49.7-50.3Hz;

(iii) a fault on the National Electricity Transmission System which:

A. could be linked to the known or reported tripping of 250MW or more as reported in (i) above; and/or

B. (as detailed in section CC6.1.4) is linked to a change in the Transmission System voltage of

I. 300kV or greater: > +/-5% for >15min; or

II. 132kV up to 300kV: > +/- 10% for >15min;

(iv) any known demand disconnected >=50MW from the National Electricity Transmission System or other lesser demand if notified to The Company; and

(v) any Demand Control action taken;

(b) a report of each such Significant Event including the following data in relation to each Significant Event as appropriate and available:

(i) the time(s) in hh.mm.ss of the Significant Event and any potentially related occurrences;

(ii) any known or reported loss of Embedded Power Station(s) with locations and ratings where available;

(iii) the Frequency record (in table and graphical format) at <=1 second intervals for 1 minute before and 1 minute after the Significant Event;

(iv) the Frequency (to 2 decimal places) immediately before the Significant Event;

(v) the Frequency (to 2 decimal places) immediately after the Significant Event;

(vi) the maximum rate of change of Frequency recorded during the Significant Event over a specified time period of 500ms;
(vii) where known, the MW of all individual losses or trips related to the Significant Event;

(viii) where known, the identity of the Users and Network Operator of all demand losses or trips related to the Significant Event;

(ix) the location of any reported Transmission fault on the network diagram and geographically;

(x) the extent of any voltage dip associated with the Significant Event;

(xi) an estimate of system inertia in MWs at the time of the Significant Event along with how it has been calculated; and

(xii) any other data available that is of value to gain a clearer understanding of the Significant Event and its potential implications; and

(c) an outline of progress towards reporting events and associated data on the National Electricity Transmission System including:

(i) three phase faults;

(ii) three phase to earth faults;

(iii) phase to phase faults;

(iv) phase to earth faults;

(v) the associated voltage dips – durations and spreads;

(vi) over-voltages;

(vii) under-voltages;

(viii) voltage dips of >50%; and

(ix) lightning strikes.

OC3.4.2 To obtain, manage, present, communicate and report the data in OC3.4.1 The Company shall:

(a) present the System Incidents Report and provide, in an annex, associated data in spreadsheet format;

(b) maintain an area of the Website with a list of all historic System Incidents Reports and information on any process required for legitimate parties to obtain the reports (if reports are not available to download); and

(c) notify all Electricity Distribution Licence holders and Network Operators of every Significant Event and request information to fulfil its duties in OC3.4.1.

OC3.4.3 The Company shall prepare and publish the System Incidents Report monthly in accordance with the following timescales:

(a) a data cut-off date of the end of each month for that reporting month;

(b) data is collated, reviewed and processed in the subsequent two months for a reporting month;

(c) System Incidents Report to be published at latest on the last working day of the second month after each reporting month (in other words the report for January would be published on the last working day of March, and so on) and submitted to the next regular Grid Code Review Panel. For the avoidance of doubt, if there are no incidents arising under OC3.4.1 (a)- (c) a System Incidents Report would, nevertheless, still be published stating that 'No System Incident occurred in month [X]'.

OC3.4.4 The Company shall prepare and publish monthly on the Website, in a spreadsheet form, System Frequency data at a maximum of one second intervals for the whole month (Historic Frequency Data) in accordance with the following timescales:
(a) a data cut-off date of the end of each month for that reporting month;
(b) data is collated, reviewed and processed in the subsequent ten working days after the end of the reporting month;
(c) **Historic Frequency Data** to be published on the eleventh working day after each reporting month (in other words the report for January would be published on the eleventh working day of February, and so on).

**OC3.4.5** The Company will use best endeavours to provide a report or reports (based on either the historic reporting methodology, or on the **Significant Incidents Reports** methodology, or a mix of the two), on events for the period from 1 November 2017 until the first **System Incidents Report** pursuant to this **Operating Code**, such a report or reports to be made available within 4 months of implementation date of the modification.

**OC3.5** **REPORTING ON FAULT EVENTS**

**OC3.5.1** The Company shall prepare and publish on their website a report giving date, time and location of actual three phase, three phase to earth, phase to phase and phase to earth fault events on the **National Electricity Transmission System**. Information shall be published as soon as reasonably practicable following such an event. For faults in which a fault ride through issue was found, where available, appropriate waveform information will be provided.

**OC3.6** **REPORTING ON LEARNING**

**OC3.6.1** Where the analysis of events occurring on the **National Electricity Transmission System** as set out in OC3.5.1 gives rise to learning points which The Company believes are relevant to the industry, The Company will publish a report explaining the events, the analysis and information gained as applicable. The contents of the report will be anonymised to avoid identification of Users, connection sites and manufacturers of Plant and Apparatus except in circumstances where OC3.6.2 applies. Where information sourced from Users or manufacturers is included, permission will be sought before publication.

**OC3.6.2** Where The Company believes that it is appropriate to identify a particular User, connection site or Plant and Apparatus, The Company shall in the first instance consult the relevant User and/or manufacturer as applicable to seek agreement for publication.

**OC3.6.3** If permission for publication is not granted by the User and/or manufacturer and The Company believes that it is appropriate to identify a particular User, connection site or Plant and Apparatus, The Company may ask the Authority for guidance regarding publication.

< END OF OPERATING CODE NO. 3 >
OPERATING CODE NO. 4
(OC4)

NOT USED

< END OF OPERATING CODE NO. 4 >
OPERATING CODE NO. 5
(OC5)
TESTING AND MONITORING

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<td>APPENDIX 4 - COMPLIANCE TESTING FOR DC CONVERTERS AT A DC CONVERTER STATION</td>
<td>45</td>
</tr>
</tbody>
</table>
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.

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, or fails to comply in the case of CC.6.3.15 or ECC 6.3.15 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, and in the case of a failure to comply with the requirements of CC.6.3.15 or ECC.6.3.15 as applicable, within 2 hours in respect of a notification to this effect under OC10 or a longer time period only where agreed by The Company, 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.
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** which has tripped off or de-loaded coincident with a fault as described in **CC.6.3.15** or **ECC.6.3.15**, resolve any non-compliance, within a reasonable period.

For the avoidance of doubt in the case of **CC.6.3.15** or **ECC.6.3.15** as applicable, the explanation may indicate that the **User** has complied with **CC.6.3.15** or **ECC.6.3.15** on the basis that:

(i) the **User** had complied with **CC.6.3.15** or **ECC.6.3.15** as applicable on the basis that the **User** has provided recordings to show the voltage waveform during the fault was beyond the conditions specified in **CC.6.3.15** or **ECC.6.3.15** as applicable; or

(ii) the **User’s Connection Point** had been de-energised by receipt of an intertrip signal from the **National Electricity Transmission System**; or

(iii) that other information has been shared between the **User** and **The Company** enabling agreement between them that compliance with **CC.6.3.15** or **ECC.6.3.15** as applicable has been confirmed.

Data relating to a fault on the **Transmission System** that **The Company** believes has led to **Users** to co-incidentally trip or de-load is to be provided by **The Company**, where available, in a file structure as agreed with the **User**. Where waveform data is available, this will be obtained from the recorder electrically closest to the **User’s Connection Point**.

**OC5.4.2.3**

In the event of a **User** being notified under **OC5.4.2.1** by **The Company** of a potential failure to comply with **CC6.3.15** or **ECC6.3.15** as applicable and where the **User** is required to provide an explanation as described in **OC5.4.2.2(c)**, the **User** shall take action to restrict the output of their **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 a level and for a period as agreed with **The Company** or until an explanation has been provided by the **User** and agreed between the **User** and **The Company** as set out under **OC5.4.2.2(c)**.

**OC5.4.2.4**

**The Company** and the **User** will discuss any 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 time(s) and date(s) for the application of the agreed parameters. For the avoidance of doubt in the case of a failure to comply with **CC.6.3.15** or **ECC.6.3.15** as applicable which requires the **User** to provide an explanation as described in **OC5.4.2.2(c)**, this may be to zero MW or another value if agreed between the **User** and **The Company**.

**OC5.4.2.5**

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, except in respect of **CC.6.3.15** or **ECC.6.3.15**, as applicable, where testing is impractical and **OC.5.4.2.6** shall apply instead.

**OC5.4.2.6**

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** identifying their non-compliance with **CC.6.3.15** or **ECC.6.3.15** as applicable by completion of their report into this as set out in **OC10**, **The Company** will as soon as reasonably practicable, issue a **Limited Operational Notification** or amend any **Interim Operational Notification**.

**OC5.5**

**PROCEDURE FOR TESTING**

**OC5.5.1**

**The Company’s Instruction For Testing**
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.

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 and ECC 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, BC.3.7.1 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.

(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.

User Request For Testing

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.
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.

Conduct Of Test

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.

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.

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

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:
<table>
<thead>
<tr>
<th>Parameter to be Tested</th>
<th>Criteria against which the test results will be assessed by The Company.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Voltage Quality</strong></td>
<td></td>
</tr>
<tr>
<td>Harmonic Content</td>
<td>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 Engineering Recommendation G5.</td>
</tr>
<tr>
<td>Phase Unbalance</td>
<td>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.</td>
</tr>
<tr>
<td></td>
<td>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.</td>
</tr>
<tr>
<td>Rapid Voltage Change</td>
<td>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)</td>
</tr>
<tr>
<td>Flicker Severity</td>
<td>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).</td>
</tr>
<tr>
<td>Voltage Fluctuation</td>
<td>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.</td>
</tr>
<tr>
<td><strong>Fault Clearance</strong></td>
<td></td>
</tr>
<tr>
<td>Fault Clearance Times</td>
<td>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</td>
</tr>
<tr>
<td>Back Up Protection</td>
<td>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</td>
</tr>
<tr>
<td>Circuit Breaker Fail</td>
<td>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)</td>
</tr>
<tr>
<td>Parameter to be Tested</td>
<td>Criteria against which the test results will be assessed by The Company</td>
</tr>
<tr>
<td>------------------------</td>
<td>------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Reactive Capability</td>
<td>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, 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 up to 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 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 all voltages.</td>
</tr>
<tr>
<td>Governor / Frequency Control</td>
<td>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.</td>
</tr>
<tr>
<td>Governor / Load / Frequency Controller System Compliance</td>
<td>Stability with Voltage: CC.6.3.4 or ECC.6.3.4</td>
</tr>
<tr>
<td>Governor / Load / Frequency Controller System Compliance</td>
<td>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</td>
</tr>
<tr>
<td>Parameter to be Tested</td>
<td>Criteria against which the test results will be assessed by The Company.</td>
</tr>
<tr>
<td>------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Fast Start</td>
<td>Ancillary Services Agreement requirements</td>
</tr>
<tr>
<td>Black Start</td>
<td>OC5.7</td>
</tr>
<tr>
<td>Excitation/Voltage Control System</td>
<td>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 and the Bilateral Agreement as applicable</td>
</tr>
<tr>
<td>Fault Ride Through and Fast Fault Current Injection</td>
<td>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 as applicable</td>
</tr>
<tr>
<td>Export and Import Limits and Dynamic Parameters</td>
<td>BC2</td>
</tr>
<tr>
<td>Synchronisation time</td>
<td>BC2.5.2.3</td>
</tr>
<tr>
<td>Run-up rates</td>
<td>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.</td>
</tr>
<tr>
<td>Run-down rates</td>
<td>BC2</td>
</tr>
<tr>
<td>Demand Response</td>
<td>DRSC.11.7</td>
</tr>
<tr>
<td>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.</td>
<td></td>
</tr>
</tbody>
</table>
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 Module, 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.
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 Procedure for a Black Start Test

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

OC5.7.2.1 Black Start Unit Tests

(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 **Power Station** 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.

OC5.7.3 **Quick Re-synchronisation Unit Test**

(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 **ECC**; 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 Modules, Power Park Modules or DC Converters 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:

(c) 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

(d) 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 Converter at a 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 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 or ECC.6.6.3.3 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%.

OC5.A.1.4 Testing not witnessed by The Company on-site

OC5.A.1.4.1.1 Where The Company has decided not to witness testing on-site, the results shall be submitted to The Company in spreadsheet format with the signal data in columns arranged as follows. Signal data denoted by “#” is not essential but if not provided the column should remain in place but without values entered. Where two signal names are given in a column these are alternatives related to the type of plant under test.

OC5.A.1.4.1.2. Where The Company has requested addition signals to be recorded prior to the testing these signals shall be placed in columns to the right of the spreadsheet.

OC5.A.1.4.2.1 Onshore Synchronous Generating Unit Excitation System and Reactive Capability

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OC5.A.1.4.2.2 Onshore Synchronous Generating Unit Frequency Response and CC.6.3.3
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OC5.A.1.4.3.1 Onshore Power Park Modules Voltage Control & Reactive Capability

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</tr>
</tbody>
</table>

# Columns may be left blank but the column must still be included in the files

OC5.A.1.4.3.2 Offshore Power Park Modules Voltage Control & Reactive Capability

<table>
<thead>
<tr>
<th>Col 1</th>
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<th>Col 4</th>
<th>Col 5</th>
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<td>Reactive</td>
<td>Connection</td>
<td>Speed</td>
<td>Freq</td>
<td>Logic /</td>
<td>Statcom or Windfarm</td>
</tr>
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<td></td>
<td>Power</td>
<td>Power</td>
<td>Point Voltage</td>
<td>/Frequency</td>
<td>Injection</td>
<td>Test Start</td>
<td>Reactive Power</td>
</tr>
<tr>
<td></td>
<td></td>
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<td>#</td>
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<thead>
<tr>
<th>Col 1</th>
<th>Col 2</th>
<th>Col 3</th>
<th>Col 4</th>
<th>Col 5</th>
<th>Col 6</th>
<th>Col 7</th>
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</thead>
<tbody>
<tr>
<td>Power</td>
<td>Available</td>
<td>Wind</td>
<td>Wind</td>
<td>Voltage</td>
<td>Voltage</td>
<td>Voltage</td>
<td>Voltage</td>
</tr>
<tr>
<td>Speed</td>
<td>Available</td>
<td>Speed</td>
<td>Direction</td>
<td>Setpoint</td>
<td>Setpoint</td>
<td>Setpoint</td>
<td>Setpoint</td>
</tr>
<tr>
<td></td>
<td></td>
<td>m/s</td>
<td></td>
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</tr>
</tbody>
</table>

# Columns may be left blank but the column must still be included in the files

OC5.A.1.4.3.3 Power Park Modules Frequency Control

<table>
<thead>
<tr>
<th>Col 1</th>
<th>Col 2</th>
<th>Col 3</th>
<th>Col 4</th>
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<th>Col 6</th>
<th>Col 7</th>
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<tbody>
<tr>
<td>Time</td>
<td>GEP</td>
<td>GEP</td>
<td>GEP</td>
<td>Speed</td>
<td>Freq</td>
<td>Logic /</td>
<td>Statcom or Windfarm</td>
</tr>
<tr>
<td></td>
<td>Active</td>
<td>Reactive</td>
<td>Connection</td>
<td>/Frequency</td>
<td>Injection</td>
<td>Test Start</td>
<td>Reactive Power</td>
</tr>
<tr>
<td></td>
<td>Power</td>
<td>Power</td>
<td>Voltage</td>
<td>#</td>
<td>#</td>
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<td>#</td>
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<tr>
<td>Col 9</td>
<td>Col 10</td>
<td>Col 11</td>
<td>Col 12</td>
<td>Col 13</td>
<td>Col 14</td>
<td>Col 15</td>
<td>Col 16</td>
</tr>
</tbody>
</table>
OC5.A.1.5.1 Where test results are completed without any presence of The Company but are relied upon as evidence of the compliance they should be accompanied by a logsheet. This sheet should be legible, in English and detail the items as indicated below:

- Time and date of test;
- Name of Power Station and module if applicable;
- Name of test engineer(s) and company name;
- Name of User representative(s) and company name;
- Type of testing being undertaken eg. voltage control;
- Ambient conditions eg. temperature, pressure, wind speed, wind direction; and
- Controller settings, eg. voltage slope, frequency droop, voltage setpoint, UEL & OEL settings.

OC5.A.1.5.2 For each test the following items should be recorded as relevant to the type of test being undertaken. Where there is uncertainty on the information to be recorded this should be discussed with The Company in advance of the test.

OC5.A.1.5.2.1 Voltage Control Tests

- Start time of each test step;
- **Active Power**;
- **Reactive Power**;
- Connection voltage;
- Voltage control setpoint, if applicable or changed;
- Voltage control slope, if applicable or changed;
- Terminal voltage if applicable;
- **Generating Unit** transformer tap position or grid transformer tap position, as applicable;
- Number of Power Park Units in service in each Power Park Module, if applicable; and
- For Offshore Connections, **Offshore Grid Entry Point** voltage.

OC5.A.1.5.2.2 Reactive Power Capability Tests

- Start time of test;
- **Active Power**;
- **Reactive Power**;
- Connection voltage;
- Terminal voltage if applicable;
- **Generating Unit** transformer tap position or grid transformer tap position as applicable;
- Number of **Power Park Units** in service in each **Power Park Module**, if applicable and
- For Offshore Connections, **Offshore Grid Entry Point** voltage.

**OC5.A.1.5.2.3** Frequency Response Capability Tests

- Start time of test;
- **Active Power**;
- **System Frequency**;
- For **CCGT Modules, Active Power** for the individual units (GT & ST);
- For boiler plant, HP steam pressure;
- Droop setting of controller if applicable;
- Number of **Power Park Units** in service in each **Power Park Module**, if applicable.; and
- For Offshore Connections, **Offshore Grid Entry Point Active Power** for each Power Park Module.

**OC5.A.1.5.3** Material changes during the test period should be recorded e.g. **Generating Units** tripping / starting, changes to tapchange positions.
APPENDIX 2 - COMPLIANCE TESTING OF SYNCHRONOUS PLANT

OC5.A.2.1 Scope

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.2.1.1 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. During 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.2.1.4 The Generator shall submit a schedule of tests to The Company in accordance with CP.4.3.1

OC5.A.2.1.5 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.2.1.6 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.
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

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

Open & Short Circuit Saturation Characteristics

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.

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.

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

Excitation System On-Load Tests

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.

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

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

<table>
<thead>
<tr>
<th>Test</th>
<th>Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Synchronous generator running rated MW at unity <strong>Power Factor</strong>. Under-excitation limit temporarily moved close to the operating point of the generator.</td>
<td></td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Test</th>
<th>Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous Generator running Rated MW and maximum lagging MVAR.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Over-excitation Limit temporarily set close to this operating point. PSS on.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
| 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
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.

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.

Where a 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.

**Preliminary Governor Frequency Response Testing**

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.

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

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.
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.

<table>
<thead>
<tr>
<th>Module Load Point</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Module Load Point 6</td>
<td>100% MEL</td>
</tr>
<tr>
<td>(Maximum Export Limit)</td>
<td></td>
</tr>
<tr>
<td>Module Load Point 5</td>
<td>95% MEL</td>
</tr>
<tr>
<td>Module Load Point 4</td>
<td>80% MEL</td>
</tr>
<tr>
<td>(Mid point of Operating Range)</td>
<td></td>
</tr>
<tr>
<td>Module Load Point 3</td>
<td>70% MEL</td>
</tr>
<tr>
<td>Module Load Point 2</td>
<td>MG</td>
</tr>
<tr>
<td>(Minimum Generation)</td>
<td></td>
</tr>
<tr>
<td>Module Load Point 1</td>
<td>DMOL</td>
</tr>
<tr>
<td>(Design Minimum Operating Level)</td>
<td></td>
</tr>
</tbody>
</table>

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 or 90 seconds, whichever is the longer. 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. When witnessed by The Company each test should be carried out as a separate injection; when not witnessed by The Company there must be sufficient time allowed between tests for the Plant to have reached a stable steady state operating condition or 90 seconds, whichever is the longer.
Figure 1: Frequency Response Capability 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

<table>
<thead>
<tr>
<th>Load Point</th>
<th>+2.0*</th>
<th>±0.02</th>
<th>-0.2</th>
<th>+0.2</th>
<th>-0.5</th>
<th>+0.5</th>
<th>+0.6</th>
<th>-0.5</th>
<th>-2.0</th>
<th>± 0***</th>
</tr>
</thead>
<tbody>
<tr>
<td>MLP6</td>
<td>BC1</td>
<td></td>
<td></td>
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<tr>
<td>MLP6 LFISM</td>
<td>BC3</td>
<td></td>
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<td>MLP5</td>
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<tr>
<td>MLP4</td>
<td>D/E</td>
<td>F</td>
<td>G</td>
<td>H</td>
<td>I</td>
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<tr>
<td>MLP4 LFISM</td>
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<tr>
<td>MLP1</td>
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</tbody>
</table>

** 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 CC GT 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.2.8.9 The target frequency adjustment facility should be demonstrated from the normal Control Point within the range of 49.9Hz to 50.1Hz by step changes to the target frequency setpoint as indicated in OC5.A.2.8 Figure 3.
* Timing can be altered with hold needed until output stabilises.

Figure 3 – Target Frequency setting changes
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

(iii) 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 during 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
The Generator shall submit a detailed schedule of tests to The Company in accordance with CP.6.3.1, and this Appendix.

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.

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.

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.

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.

Pre 20% (or <50MW) Synchronised Power Park Module basic Voltage Control Tests

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.

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.

Pre 70% Power Park Module Tests

For Power Park Modules with Registered Capacity  \( \geq \)100MW only. 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

Reactive Capability Test

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.

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.

Embedded Generators 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
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.

The following tests shall be completed:

(i) Operation in excess of 50% Rated MW and maximum continuous lagging Reactive Power for 60 minutes. For the avoidance of doubt this test must start with Active Power output in excess of 85% of Registered Capacity of the Power Park Module as OC5.A.3.4.1 and must not fall below 50% of Registered Capacity of the Power Park Module during the 60 minutes.

(ii) Operation in excess of 50% Rated MW and maximum continuous leading Reactive Power for 60 minutes. For the avoidance of doubt this test must start with Active Power output in excess of 85% of Registered Capacity of the Power Park Module as OC5.A.3.4.1 and must not fall below 50% of Registered Capacity of the Power Park Module during the 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.

Within this OC5 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.

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.

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.

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 injections into the Power Park Module or OTSUA voltage reference, steps of ±1%, ±2% and ±4% shall be applied to the voltage control system reference summing junction. The injection shall be maintained for a minimum of 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 (eg. mechanically switched shunt reactors or capacitors) additional tests will be required to demonstrate that the overall performance of the voltage control system when switching these devices as part of the response is in accordance with Grid Code and Bilateral Agreement requirements.

OC5.A.3.5.6 Tests to be completed:

(i)

![Diagram](image)

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

(ii)

![Diagram](image)

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

OC5.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.3.5.8 In the case of Power Park Modules that do not provide voltage control down to zero Active Power a test to demonstrate the smooth transition from voltage control mode to unity Power Factor shall be carried out. The Power Park Module voltage setpoint should be altered to produce lagging Reactive Power or absorbing leading Reactive Power at a low Active Power level where voltage control is provided. The Power Park Module Active Power should then be reduced to zero Active Power as a ramp over a short period (60 seconds is suggested).

OC5.A.3.6 Frequency Response Tests

OC5.A.3.6.1 This section describes the procedure for performing frequency response testing on a 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 or ECC.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.

<table>
<thead>
<tr>
<th>Test No (Figure 1)</th>
<th>Frequency Injection</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>• Inject - 0.5Hz frequency fall over 10 sec&lt;br&gt;• Hold until conditions stabilise&lt;br&gt;• Remove the injected signal</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>• Inject +0.5Hz frequency rise over 10 sec&lt;br&gt;• Hold until conditions stabilise&lt;br&gt;• Remove the injected signal</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>• Inject -0.5Hz frequency fall over 10 sec&lt;br&gt;• Hold for a further 20 sec&lt;br&gt;• At 30 sec from the start of the test, Inject a +0.3Hz frequency rise over 30 sec.&lt;br&gt;• Hold until conditions stabilise&lt;br&gt;• Remove the injected signal</td>
<td></td>
</tr>
</tbody>
</table>

**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**.

<table>
<thead>
<tr>
<th>Module Load Point 6 (Maximum Export Limit)</th>
<th>100% MEL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Module Load Point 5</td>
<td>90% MEL</td>
</tr>
<tr>
<td>Module Load Point 4 (Mid point of Operating Range)</td>
<td>80% MEL</td>
</tr>
<tr>
<td>Module Load Point 3</td>
<td>DMOL + 0.6 x (80% MEL – DMOL)</td>
</tr>
<tr>
<td>Module Load Point 2 (Minimum Generation)</td>
<td>DMOL + 0.3 x (80% MEL – DMOL)</td>
</tr>
<tr>
<td>Module Load Point 1 (Designed Minimum Operating Level)</td>
<td>DMOL</td>
</tr>
</tbody>
</table>
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 or 90 seconds, whichever is the longer. 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. When witnessed by The Company each test should be carried out as a separate injection; when not witnessed by The Company there must be sufficient time allowed between tests for the Active Power (MW) output of the Power Park Module to have stabilised or 90 seconds, whichever is the longer.

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

<table>
<thead>
<tr>
<th>Load Point</th>
<th>+2.0*</th>
<th>+0.02</th>
<th>-0.2</th>
<th>+0.2</th>
<th>-0.5</th>
<th>+0.5</th>
<th>+0.6</th>
<th>-0.5</th>
<th>-2.0</th>
<th>± 0**</th>
</tr>
</thead>
<tbody>
<tr>
<td>MLP6</td>
<td></td>
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<tr>
<td>MLP6 LFSM</td>
<td>BC1</td>
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<td></td>
<td>L</td>
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<td>MLP5</td>
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<td>A</td>
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<td>BC3</td>
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<td></td>
<td></td>
<td>N</td>
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<td>MLP1</td>
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</tbody>
</table>

** 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.

** 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.

** 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.

** 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.

The **Target Frequency** adjustment facility should be demonstrated from the normal control point within the range of 49.9Hz to 50.1Hz by step changes to the **Target Frequency** setpoint as indicated in OC5.A.3.6 Figure 3.
OC5.A.3.7 Fault Ride Through Testing

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 (e.g. in the case of a wind turbine it would include the full wind turbine nacelle structure, all inverters and converters along with step up transformer to medium voltage, all control systems including pitch control emulation) and shall be conducted with sufficient power input 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 or other decoupling equipment 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.
<table>
<thead>
<tr>
<th>3 Phase</th>
<th>Phase to Phase</th>
<th>2 Phase to Earth</th>
<th>1 Phase to Earth</th>
<th>Grid Code Ref</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.14s</td>
<td>0.14s</td>
<td>0.14s</td>
<td>0.14s</td>
<td>CC.6.3.15a</td>
</tr>
<tr>
<td>0.384s</td>
<td></td>
<td></td>
<td></td>
<td>CC.6.3.15b</td>
</tr>
<tr>
<td>0.710s</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2.5s</td>
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<td></td>
</tr>
<tr>
<td>180.0s</td>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

OC5.A.3.7 Table 1 – Types of fault for fault ride through testing
OC5.A.3.8 Reactive Power Transfer / Voltage Control Tests for Offshore Power Park Modules

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.
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

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

The Company may agree a reduction from the requirements set out in CP.A.7.2 to CP.A.7.5 for on-site testing where suitable factory acceptance testing on a representative installation with the same equipment and settings of the HVDC Equipment that can, in The Company’s opinion, reasonably represent the performance of the installed HVDC Equipment at that site. This is also conditional on The Company and the DC Converter Station owner agreeing sufficient on-site testing of the fully commissioned DC Converter Station to demonstrate that the factory acceptance tests are valid. If in the reasonable opinion of The Company, the on-site testing does not demonstrate the factory acceptance tests are valid then the full set of on-site tests should be carried out.

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 Reactive Control Testing For DC Converters (Current Source Technology)

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](image1)

OC5.A.4.4 Voltage Control Tests

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 is 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  For step injections into the DC Converter voltage reference, steps of ±1%, ±2% and ±4% 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.4.5  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.4.6  Tests to be completed:

(i)

![Transformer tap sequence for voltage control tests](image1)

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

(ii)

![Step injection sequence for voltage control tests](image2)

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 is 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 is 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.

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

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                          | 80% MEL  |
| Module Load Point 3                          | DMOL + 0.6 x (80% MEL – DMOL) |
| Module Load Point 2 (Minimum Generation)     | DMOL + 0.3 x (80% MEL – DMOL) |
| Module Load Point 1 (Designed Minimum Operating Level) | DMOL |
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.

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 or 90 seconds whichever is the longer. 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. When witnessed by **The Company** each test should be carried out as a separate injection, when not witnessed by **The Company** there must be sufficient time allowed between tests for the **Active Power** (MW) output of the **HVDC Equipment** to have stabilised or 90 seconds, whichever is the longer.

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**OC5.A.4.5.7**

<table>
<thead>
<tr>
<th>Load Point</th>
<th>LF Event Profile 1</th>
<th>LF Ramp -0.1Hz</th>
<th>LF Ramp +0.1Hz</th>
<th>HF Ramp -0.2Hz</th>
<th>HF Ramp +0.2Hz</th>
<th>HF Ramp -0.5Hz</th>
<th>HF Ramp +0.5Hz</th>
<th>LF Event Profile 2</th>
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<tbody>
<tr>
<td>MLP6</td>
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<td></td>
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<td>MLP4</td>
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<td>MLP1</td>
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</tr>
</tbody>
</table>

**OC5.A.4.5. Figure 1 – Frequency response volume 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 the 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 of 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:

<table>
<thead>
<tr>
<th>Initial Output</th>
<th>65%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Designed Minimum Operating Level</td>
<td>20%</td>
</tr>
<tr>
<td>Frequency Controller Droop</td>
<td>4%</td>
</tr>
<tr>
<td>Frequency to be injected =</td>
<td>((0.65 - 0.20) \times 0.04 \times 50 = 0.9Hz)</td>
</tr>
</tbody>
</table>

** 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.

The Target Frequency adjustment facility should be demonstrated from the normal Control Point within the range of 49.9Hz to 50.1Hz by step changes to the Target Frequency setpoint as indicated in OC5.A.4.6 Figure 3.
OC5.A.4.6. Figure 3 – Target Frequency setting changes

* Timing can be altered with hold needed until output stabilises.

< END OF OPERATING CODE NO. 5 >
OPERATING CODE NO. 6
(OC6)

DEMAND CONTROL

CONTENTS

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OC6.1  **INTRODUCTION**

OC6.1.1  Operating Code No.6 ("OC6") is concerned with the provisions to be made by Network Operators, and in relation to Non-Embedded Customers by The Company, to permit the reduction of Demand in the event of insufficient Active Power generation being available to meet Demand, or in the event of breakdown or operating problems (such as in respect of System Frequency, System voltage levels or System thermal overloads) on any part of the National Electricity Transmission System.

OC6.1.2  OC6 deals with the following:

(a) Customer voltage reduction initiated by Network Operators (other than following the instruction of The Company);

(b) Customer Demand reduction by Disconnection initiated by Network Operators (other than following the instruction of The Company);

(c) Demand reduction instructed by The Company;

(d) automatic low frequency Demand Disconnection; and

(e) emergency manual Demand Disconnection.

The term "Demand Control" is used to describe any or all of these methods of achieving a Demand reduction.

OC6.1.3  The procedure set out in OC6 includes a system of warnings to give advance notice of Demand Control that may be required by The Company under this OC6.

OC6.1.4  Data relating to Demand Control should include details relating to MW

OC6.1.5  The Electricity Supply Emergency Code as reviewed and published from time to time by the appropriate government department for energy emergencies provides that in certain circumstances consumers are given a certain degree of "protection" when rota disconnections are implemented pursuant to a direction under the Energy Act 1976. No such protection can be given in relation to Demand Control under the Grid Code.

To invoke the Electricity Supply Emergency Code the Secretary of State will issue direction(s) to all Network Operators affected, exercising emergency powers under the Electricity Act 1989 or by virtue of an Order in Council under the Energy Act 1976. Following the issuance of such direction, The Company will act to coordinate the implementation of an agreed schedule of rota disconnections across all affected Network Operators’ licence area(s) and to disseminate any information as necessary throughout the period of the emergency in accordance with the instructions The Company receives from the Secretary of State or those authorised on their behalf for this purpose.

OC6.1.6  Connections between Large Power Stations and the National Electricity Transmission System and between such Power Stations and a User System will not, as far as possible, be disconnected by The Company pursuant to the provisions of OC6 insofar as that would interrupt supplies

(a) for the purposes of operation of the Power Station (including Start-Up and shutting down);

(b) for the purposes of keeping the Power Station in a state such that it could be Started-up when it is off-Load for ordinary operational reasons; or

(c) for the purposes of compliance with the requirements of a Nuclear Site Licence.

Demand Control pursuant to this OC6 therefore applies subject to this exception.
OC6.2 OBJECTIVE

OC6.2.1 The overall objective of OC6 is to require the provision of facilities to enable The Company to achieve reduction in Demand that will either avoid or relieve operating problems on the National Electricity Transmission System, in whole or in part, and thereby to enable The Company to instruct Demand Control in a manner that does not unduly discriminate against, or unduly prefer, any one or any group of Suppliers or Network Operators or Non-Embedded Customers. It is also to ensure that The Company is notified of any Demand Control utilised by Users other than following an instruction from The Company.

OC6.2.2 For certain Grid Supply Points in Scotland it is recognised that it may not be possible to meet the requirements in OC6.4.5(b), OC6.5.3(b) (in respect of Demand Disconnection only), OC6.5.6 (ii), OC6.6.2 (c) and OC6.7.2 (b). In these circumstances The Company and the relevant Network Operator(s) will agree equivalent requirements covering a number of Grid Supply Points. If The Company and the relevant Network Operator fail to agree equivalent requirements covering a number of Grid Supply Points, then the relevant Network Operator will apply the provisions of OC6.4.5(b), OC6.5.3(b) (in respect of Demand Disconnection only), OC6.5.6(ii), OC6.6.2(c) and OC6.7.2(b) as evenly as reasonably practicable over the relevant Network Operator’s entire System.

OC6.3 SCOPE

OC6.3.1 OC6 applies to The Company and to Users which in OC6 means:

(a) Generators; and
(b) Network Operators.

It also applies to The Company in relation to Non-Embedded Customers.

OC6.3.2 Explanation

OC6.3.2.1 (a) Although OC6 does not apply to Suppliers, the implementation of Demand Control may affect their Customers.

(b) In all situations envisaged in OC6, Demand Control is exercisable:

(i) by reference to a Network Operator’s System; or

(ii) by The Company in relation to Non-Embedded Customers.

(c) Demand Control in all situations relates to the physical organisation of the Total System, and not to any contractual arrangements that may exist.

OC6.3.2.2 (a) Accordingly, Demand Control will be exercisable with reference to, for example, five per cent (or such other figure as may be utilised under OC6.5) tranches of Demand by a Network Operator.

(b) For a Supplier, whose Customers may be spread throughout a number of User Systems (and the National Electricity Transmission System), to split its Customers into five per cent (or such other figure as may be utilised under OC6.5) tranches of Demand would not result in Demand Control being implemented effectively on the Total System.

(c) Where Demand Control is needed in a particular area, The Company would not know which Supplier to contact and (even if it were to) the resulting Demand Control implemented, because of the diversity of contracts, may well not produce the required result.

OC6.3.2.3 (a) Suppliers should note, however, that, although implementation of Demand Control in respect of their Customers is not exercisable by them, their Customers may be affected by Demand Control.

(b) This will be implemented by Network Operators where the Customers are within User Systems directly connected to the National Electricity Transmission System and by The Company where they are Non-Embedded Customers.
(c) The contractual arrangements relating to Customers being supplied by Suppliers will, accordingly, need to reflect this.

(d) The existence of a commercial arrangement for the provision of Customer Demand Management or Commercial Ancillary Services does not relieve a Network Operator from the Demand Control provisions of OC6.5, OC6.6 and OC6.7, which may be exercised from time to time.

OC6.4 PROCEDURE FOR THE NOTIFICATION OF DEMAND CONTROL INITIATED BY NETWORK OPERATORS (OTHER THAN FOLLOWING THE INSTRUCTION OF THE COMPANY)

OC6.4.1 Pursuant to the provisions of OC1, in respect of the time periods prior to 1100 hours each day, each Network Operator will notify The Company of all Customer voltage reductions and/or restorations and Demand Disconnection or reconnection, on a Grid Supply Point and half-hourly basis, which will or may, either alone or when aggregated with any other Demand Control planned by that Network Operator, result in a Demand change equal to or greater than the Demand Control Notification Level averaged over any half hour on any Grid Supply Point, which is planned to be instructed by the Network Operator other than following an instruction from The Company relating to Demand reduction.

OC6.4.2 Under OC6, each Network Operator will notify The Company in writing by 1100 hours each day (or such other time specified by The Company from time to time) for the next day (except that it will be for the next 3 days on Fridays and 2 days on Saturdays and may be longer (as specified by The Company at least one week in advance) to cover holiday periods) of Customer voltage reduction or Demand Disconnection which will or may result in a Demand change equal to or greater than the Demand Control Notification Level averaged over any half hour on any Grid Supply Point, (or which when aggregated with any other Demand Control planned by that Network Operator is equal to or greater than the Demand Control Notification Level), planned to take place during the next Operational Day.

OC6.4.3 When the Customer voltage reduction or Demand Disconnection which may result in a Demand change equal to or greater than the Demand Control Notification Level averaged over any half hour on any Grid Supply Point (or which when aggregated with any other Demand Control planned or implemented by that Network Operator is equal to or greater than the Demand Control Notification Level) is planned after 1100 hours, each Network Operator must notify The Company as soon as possible after the decision to implement has been made. If the Customer voltage reduction or Demand Disconnection is implemented immediately after the decision to implement is made, each Network Operator must notify The Company within five minutes of implementation.

OC6.4.4 Where, after The Company has been notified, whether pursuant to OC1, OC6.4.2 or OC6.4.3, the planned Customer voltage reduction or Demand Disconnection is changed, the Network Operator will notify The Company as soon as possible of the new plans, or if the Customer voltage reduction or Demand Disconnection implemented is different to that notified, the Network Operator will notify The Company of what took place within five minutes of implementation.

OC6.4.5 Any notification under OC6.4.2, OC6.4.3 or OC6.4.4 will contain the following information on a Grid Supply Point and half hourly basis:

(a) the proposed (in the case of prior notification) and actual (in the case of subsequent notification) date, time and duration of implementation of the Customer voltage reduction or Demand Disconnection; and

(b) the proposed reduction in Demand by use of the Customer voltage reduction or Demand Disconnection.

OC6.4.6 Pursuant to the provisions of OC1.5.6, each Network Operator will supply to The Company details of the amount of Demand reduction actually achieved by use of the Customer voltage reduction or Demand Disconnection.
PROCEDURE FOR THE IMPLEMENTATION OF DEMAND CONTROL ON THE INSTRUCTIONS OF THE COMPANY

OC6.5.1 A National Electricity Transmission System Warning - High Risk of Demand Reduction will, where possible, be issued by The Company, as more particularly set out in OC6.5.4, OC7.4.8 and BC1.5.4 when The Company anticipates that it will or may instruct a Network Operator to implement Demand reduction. It will, as provided in OC6.5.10 and OC7.4.8.2, also be issued to Non-Embedded Customers.

OC6.5.2 Where The Company expects to instruct Demand reduction within the following 30 minutes, The Company will where possible, issue a National Electricity Transmission System Warning - Demand Control Imminent in accordance with OC7.4.8.2(c) and OC7.4.8.6.

OC6.5.3 (a) Whether a National Electricity Transmission System Warning - High Risk of Demand Reduction or National Electricity Transmission System Warning - Demand Control Imminent has been issued or not:

(i) provided the instruction relates to not more than 20 per cent of its total Demand (measured at the time the Demand reduction is required); and

(ii) if the instruction relates to less than 20 per cent of its total Demand, is in

- two voltage reduction stages of between 2 and 4 percent, each of which can be expected to deliver around 1.5 percent Demand reduction; and

- up to three Demand Disconnection stages, each of which can reasonably be expected to deliver between four and six percent Demand reduction,

each Network Operator will abide by the instructions of The Company, which should specify whether a voltage reduction or Demand Disconnection stage is required; or

(iii) if the instruction relates to less than 20 per cent of its total Demand, is in four Demand Disconnection stages each of which can reasonably be expected to deliver between four and six percent Demand reduction,

each Network Operator will abide by the instructions of The Company with regard to Demand reduction under OC6.5 without delay.

(b) The Demand reduction must be achieved within the Network Operator's System as far as possible uniformly across all Grid Supply Points (unless otherwise specified in the National Electricity Transmission System Warning - High Risk of Demand Reduction) either by Customer voltage reduction or by Demand Disconnection.

(c) Demand Control initiated by voltage reduction shall be initiated as soon as possible but in any event no longer than two minutes from the instruction being received from The Company, and completed within 10 minutes of the instruction being received from The Company.

(d) Demand Control initiated by Demand Disconnection shall be initiated as soon as possible but in any event no longer than two minutes from the instruction being received from The Company, and completed within five minutes of the instruction being received from The Company.

(e) Each Network Operator must notify The Company in writing by calendar week 24 each year, for the succeeding Financial Year onwards, whether Demand Control is to be implemented either:

i) by a combination of voltage reduction and Demand Disconnection; or

ii) Demand Disconnection alone;

Together with the magnitude of the voltage reduction stages (where applicable) and for Demand Disconnection stages, the demand reduction anticipated. Thereafter, any changes must be notified in writing to The Company at least 10 Business Days prior to
Where The Company wishes to instruct a Demand reduction of more than 20 per cent of a Network Operator's Demand (measured at the time the Demand reduction is required), it shall, if it is able, issue a National Electricity Transmission System Warning - High Risk of Demand Reduction to the Network Operator by 1600 hours on the previous day. The warning will state the percentage level of Demand reduction that The Company may want to instruct (measured at the time the Demand reduction is required).

The National Electricity Transmission System Warning - High Risk of Demand Reduction will specify the percentage of Demand reduction that The Company may require in integral multiples of the percentage levels notified by Users under OC6.5.3(c) up to (and including) 20 per cent and of five per cent above 20 per cent and will not relate to more than 40 per cent of Demand (measured at the time the Demand reduction is required) of the Demand on the User System of a Network Operator.

If The Company has issued the National Electricity Transmission System Warning - High Risk of Demand Reduction by 1600 hours on the previous day, on receipt of it, the relevant Network Operator shall make available the percentage reduction in Demand specified for use within the period of the National Electricity Transmission System Warning.

If The Company has not issued the National Electricity Transmission System Warning - High Risk of Demand Reduction by 1600 hours the previous day, but after that time, the Network Operator shall make available as much of the required Demand reduction as it is able, for use within the period of the National Electricity Transmission System Warning.

If The Company has given a National Electricity Transmission System Warning - High Risk of Demand Reduction to a Network Operator, and has issued it by 1600 hours on the previous day, it can instruct the Network Operator to reduce its Demand by the percentage specified in the National Electricity Transmission System Warning.

The Company accepts that if it has not issued the National Electricity Transmission System Warning - High Risk of Demand Reduction by 1600 hours on the previous day or if it has issued it by 1600 hours on the previous day, but it requires a further percentage of Demand reduction (which may be in excess of 40 per cent of the total Demand on the User System of the Network Operator (measured at the time the Demand reduction is required) from that set out in the National Electricity Transmission System Warning, it can only receive an amount that can be made available at that time by the Network Operator.

Other than with regard to the proviso, the provisions of OC6.5.3 shall apply to those instructions.

Once a Demand reduction has been applied by a Network Operator at the instruction of The Company, the Network Operator may interchange the Customers to whom the Demand reduction has been applied provided that,

(i) the percentage of Demand reduction at all times within the Network Operator’s System does not change; and

(ii) at all times it is achieved within the Network Operator’s System as far as possible uniformly across all Grid Supply Points (unless otherwise specified in the National Electricity Transmission System Warning - High Risk of Demand Reduction if one has been issued),

until The Company instructs that Network Operator in accordance with OC6.
OC6.5.7 Each **Network Operator** will abide by the instructions of **The Company** with regard to the restoration of **Demand** under OC6.5 without delay. It shall not restore **Demand** until it has received such instruction. The restoration of **Demand** must be achieved as soon as possible and the process of restoration must begin within 2 minutes of the instruction being given by **The Company**.

OC6.5.8 In circumstances of protracted shortage of generation or where a statutory instruction has been given (eg. a fuel security period) and when a reduction in **Demand** is envisaged by **The Company** to be prolonged, **The Company** will notify the **Network Operator** of the expected duration.

OC6.5.9 The **Network Operator** will notify **The Company** in writing that it has complied with **The Company's** instruction under OC6.5, within five minutes of so doing, together with an estimation of the **Demand** reduction or restoration achieved, as the case may be.

OC6.5.10 **The Company** may itself implement **Demand** reduction and subsequent restoration on **Non-Embedded Customers** as part of a **Demand Control** requirement and it will organise the **National Electricity Transmission System** so that it will be able to reduce **Demand** by **Disconnection** of, or **Customer** voltage reduction to, all or any **Non-Embedded Customers**. Equivalent provisions to those in OC6.5.4 shall apply to issuing a **National Electricity Transmission System Warning - High Risk of Demand Reduction** to **Non-Embedded Customers**, as envisaged in OC7.4.8.

OC6.5.11 Pursuant to the provisions of OC1.5.6, the **Network Operator** will supply to **The Company** details of the amount of **Demand** reduction or restoration actually achieved.
OC6.6 AUTOMATIC LOW FREQUENCY DEMAND DISCONNECTION

OC6.6.1 Each Network Operator will make arrangements that will enable automatic low Frequency Disconnection of at least:

(i) 60 per cent of its total Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand where such Network Operator’s System is connected to the National Electricity Transmission System in NGET’s Transmission Area

(ii) 40 per cent of its total Demand (based on Annual ACS Conditions) at the time of forecast National Electricity Transmission System peak Demand where such Network Operator’s System is connected to the National Electricity Transmission System in either SPT’s or SHETL’s Transmission Area

in order to seek to limit the consequences of a major loss of generation or an Event on the Total System which leaves part of the Total System with a generation deficit. Where a Network Operator’s System is connected to the National Electricity Transmission System in more than one Transmission Area, the figure above for the Transmission Area in which the majority of the Network Operator’s Demand is connected shall apply.

OC6.6.2 (a) The Demand of each Network Operator which is subject to automatic low Frequency Disconnection will be split into discrete MW blocks.

(b) The number, size (% Demand) and the associated low Frequency settings of these blocks, will be as specified in Table CC.A.5.5.1a and Table ECC.A.5.5.1a. The Company will keep the settings under review.

(c) The distribution of the blocks will be such as to give a reasonably uniform Disconnection within the Network Operator’s System, as the case may be, across all Grid Supply Points.

(d) Each Network Operator will notify The Company in writing by calendar week 24 each year of the details of the automatic low Frequency Demand Disconnection on its User System. The information provided should identify, for each Grid Supply Point at the date and time of the annual peak of the National Electricity Transmission System Demand at Annual ACS Conditions (as notified pursuant to OC1.4.2), the frequency settings at which Demand Disconnection will be initiated and the amount of Demand disconnected at each such setting.

OC6.6.3 Where conditions are such that, following automatic low Frequency Demand Disconnection, and the subsequent Frequency recovery, it is not possible to restore a large proportion of the total Demand so disconnected within a reasonable period of time, The Company may instruct a Network Operator to implement additional Demand Disconnection manually, and restore an equivalent amount of the Demand that had been disconnected automatically. The purpose of such action is to ensure that a subsequent fall in Frequency will again be contained by the operation of automatic low Frequency Demand Disconnection.

OC6.6.4 Once an automatic low Frequency Demand Disconnection has taken place, the Network Operator on whose User System it has occurred, will not reconnect until The Company instructs that Network Operator to do so in accordance with OC6.

OC6.6.5 Once the Frequency has recovered, each Network Operator will abide by the instructions of The Company with regard to reconnection under OC6.6 without delay. Reconnection must be achieved as soon as possible and the process of reconnection must begin within 2 minutes of the instruction being given by The Company.

OC6.6.6 (a) Non-Embedded Customers Pumped Storage Generators and Pumped Storage Generators, must provide automatic low Frequency disconnection, which will be split into discrete blocks. For the avoidance of doubt, the data required from Pumped Storage Generators and Electricity Storage Modules would only apply when they operate in a mode analogous to Demand.
(b) The number and size of blocks and the associated low Frequency settings will be as specified by The Company by week 24 each calendar year following discussion with the Non-Embedded Customers and, Pumped Storage Generators in accordance with the relevant Bilateral Agreement. For the avoidance of doubt, the data required Pumped Storage Generators and Electricity Storage Modules would only apply when they operate in a mode analogous to Demand.

OC6.6.7  
(a) In addition, Generators may wish to disconnect Power Generating Modules and/or Generating Units from the System, either manually or automatically, should they be subject to Frequency levels which could result in Power Generating Module and/or Generating Unit damage.

(b) This Disconnection facility on such a Power Generating Module and/or Generating Unit directly connected to the National Electricity Transmission System, will be agreed with The Company in accordance with the Bilateral Agreement.

(c) Any Embedded Power Stations will need to agree this Disconnection facility with the relevant User to whose System that Power Station is connected, which will then need to notify The Company of this.

OC6.6.8  
The Network Operator or Non-Embedded Customer, as the case may be, will notify The Company with an estimation of the Demand reduction which has occurred under automatic low Frequency Demand Disconnection and similarly notify the restoration, as the case may be, in each case within five minutes of the Disconnection or restoration.

OC6.6.9  
Pursuant to the provisions of OC1.5.6 the Network Operator and Non-Embedded Customer will supply to The Company details of the amount of Demand reduction or restoration actually achieved.

OC6.6.10  
(a) In the case of a User, it is not necessary for it to provide automatic low Frequency disconnection under OC6.6 only to the extent that it is providing, at the time it would be so needed, low Frequency disconnection at a higher level of Frequency as an Ancillary Service, namely if the amount provided as an Ancillary Service is less than that required under OC6.6 then the User must provide the balance required under OC6.6 at the time it is so needed.

(b) The provisions of OC7.4.8 relating to the use of Demand Control should be borne in mind by Users.

OC6.7  
EMERGENCY MANUAL DISCONNECTION

OC6.7.1  
Each Network Operator will make arrangements that will enable it, following an instruction from The Company, to disconnect Customers on its User System under emergency conditions irrespective of Frequency within 30 minutes. It must be possible to apply the Demand Disconnections to individual or specific groups of Grid Supply Points, as determined by The Company.

OC6.7.2  
(a) Each Network Operator shall provide The Company in writing by week 24 in each calendar year, in respect of the next following year beginning week 24, on a Grid Supply Point basis, with the following information (which is set out in a tabular format in the Appendix):

(i) its total peak Demand (based on Annual ACS Conditions); and

(ii) the percentage value of the total peak Demand that can be disconnected (and must include that which can also be reduced by voltage reduction, where applicable) within timescales of 5/10/15/20/25/30 minutes.

(b) The information should include, in relation to the first 5 minutes, as a minimum, the 20% of Demand that must be reduced on instruction under OC6.5.
OC6.7.3 Each **Network Operator** will abide by the instructions of **The Company** with regard to **Disconnection** under OC6.7 without delay, and the **Disconnection** must be achieved as soon as possible after the instruction being given by **The Company**, and in any case, within the timescale registered in OC6.7. The instruction may relate to an individual **Grid Supply Point** and/or groups of **Grid Supply Points**.

OC6.7.4 **The Company** will notify a **Network Operator** who has been instructed under OC6.7, of what has happened on the **National Electricity Transmission System** to necessitate the instruction, in accordance with the provisions of OC7 and, if relevant, OC10.

OC6.7.5 Once a **Disconnection** has been applied by a **Network Operator** at the instruction of **The Company**, that **Network Operator** will not reconnect until **The Company** instructs it to do so in accordance with OC6.

OC6.7.6 Each **Network Operator** will abide by the instructions of **The Company** with regard to reconnection under OC6.7 without delay, and shall not reconnect until it has received such instruction and reconnection must be achieved as soon as possible and the process of reconnection must begin within 2 minutes of the instruction being given by **The Company**.

OC6.7.7 **The Company** may itself disconnect manually and reconnect **Non-Embedded Customers** as part of a **Demand Control** requirement under emergency conditions.

OC6.7.8 If **The Company** determines that emergency manual **Disconnection** referred to in OC6.7 is inadequate, **The Company** may disconnect **Network Operators** and/or **Non-Embedded Customers** at **Grid Supply Points**, to preserve the security of the **National Electricity Transmission System**.

OC6.7.9 Pursuant to the provisions of OC1.5.6 the **Network Operator** will supply to **The Company** details of the amount of **Demand** reduction or restoration actually achieved.

OC6.8 **OPERATION OF THE BALANCING MECHANISM DURING DEMAND CONTROL**

**Demand Control** will constitute an **Emergency Instruction** in accordance with BC2.9 and it may be necessary to depart from normal **Balancing Mechanism** operation in accordance with BC2 in issuing **Bid-Offer Acceptances**. **The Company** will inform affected **BM Participants** in accordance with the provisions of OC7.
APPENDIX 1 - EMERGENCY MANUAL DEMAND REDUCTION/DISCONNECTION SUMMARY SHEET
(As set out in OC6.7)

NETWORK OPERATOR: __________________________ [YEAR] PEAK: __________

<table>
<thead>
<tr>
<th>GRID SUPPLY POINT (Name)</th>
<th>PEAK MW</th>
<th>% OF GROUP DEMAND DISCONNECTION (AND/OR REDUCTION IN THE CASE OF THE FIRST 5 MINUTES) (CUMULATIVE)</th>
<th>REMARKS</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>TIME (MINS)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>5</td>
<td>10</td>
</tr>
</tbody>
</table>

Notes:
1. Data to be provided annually by week 24 to cover the following year.

< END OF OPERATING CODE NO. 6 >
## OPERATING CODE NO. 6B
*(OC6B)*

### EMBEDDED GENERATION CONTROL

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OC6B.1 INTRODUCTION

OC6B.1.1 Operating Code No.6B ("OC6B") is concerned with the provisions to be made by Network Operators to reduce the Active Power output from Embedded Power Stations;

a) at times when there is a large amount of Active Power on the System from generation plant that has low (or no) inertia, to secure against the largest loss of Load, as determined under BC1.5.5; and

b) in emergency circumstances including in the event of breakdown or operating problems (such as in respect of System Frequency, System voltage levels or System thermal overloads) on any part of the National Electricity Transmission System.

OC6B.1.2 OC6B deals with Embedded Generation Control instructed by The Company. The term "Embedded Generation Control" is used to describe a reduction in the Active Power output of Embedded Power Stations. Embedded Power Stations that may be subject to Embedded Generation Control include Embedded Power Stations connected to a Network Operator's System and whose owners or operators are not BM Participants.

OC6B.1.3 The procedure set out in OC6B includes a system of warnings to give advance notice, where possible, of Embedded Generation Control that may be required by The Company under this OC6B.

OC6B.1.4 Data relating to Embedded Generation Control should include details relating to Active Power measured in Megawatts (MW).

OC6B.1.5 The Electricity Supply Emergency Code, as reviewed and published from time to time by the appropriate government department for energy emergencies, provides that in certain circumstances consumers are given a certain degree of "protection" when rota disconnections are implemented pursuant to a direction under the Energy Act 1976. Where relevant in terms of the incidental disconnection of demand as part of Embedded Generation Control, no such protection can be given in relation to Embedded Generation Control under the Grid Code.

OC6B.2 OBJECTIVE

OC6B.2.1 The overall objective of OC6B is concerned with the provisions to be made by Network Operators to reduce the Active Power output from Embedded Power Stations that will either avoid or relieve operational issues, in whole or in part, and thereby to enable The Company to instruct Embedded Generation Control in a manner that does not unduly discriminate against, or unduly prefer, any one or any group of Generators or Suppliers or Network Operators.

OC6B.3 SCOPE

OC6B.3.1 OC6B applies to The Company and to Users which in OC6B means:

(a) Generators; and

(b) Network Operators.

OC6B.3.2 Explanation
OC6B.3.2.1
(a) In all situations envisaged in OC6B, Embedded Generation Control will be implemented by one or more Network Operators; and
(b) Embedded Generation Control in all situations relates to the physical organisation of the Total System, and not to any contractual arrangements that may exist.

OC6B.3.2.2 Where Embedded Generation Control instructions are issued by The Company these may:

a) require the Network Operator to achieve a reduction in Active Power output at specified Embedded Power Station(s);
b) be for the Network Operator to achieve a reduction in Active Power output of Embedded Power Stations, supplied via one or more specified Grid Supply Point(s), of a specified value; or
c) be for the Network Operator to achieve a reduction in Active Power output of Embedded Power Stations, supplied via one or more specified Grid Supply Point(s), of a specified proportion of the aggregate Active Power output compared to the Active Power output before such an instruction was issued.

In any case, reasonable endeavours shall be employed by the Network Operator to ensure that the reduction in Active Power output specified in the instruction is achieved, considering also the principles relating to prioritisation set out in OC6B.5.1 where appropriate. Even when instructed to do so by The Company, the Network Operator will not be required to reduce the Active Power output from one or more Embedded Power Stations by more than the Active Power output from those Embedded Power Stations supplied via the specified Grid Supply Point(s).

OC6B.3.2.3 Network Operators may where necessary (for example where timescales do not allow otherwise) implement Embedded Generation Control instructions by Embedded Generation De-energisation based on Registered Capacity so long as reasonable endeavours are employed by the Network Operator to ensure that the reduction in Active Power output specified in the instruction from The Company is achieved.

OC6B.3.2.4 An instruction from The Company to the Network Operator will be given to allow the Network Operator to arrange with Embedded Power Stations subject to Embedded Generation Control to resume normal operation. Such arrangements shall not commence until such an instruction has been received.

OC6B.3.2.5 The existence of any other arrangements for the management of Embedded Power Stations by a Network Operator will not relieve a Network Operator from the Embedded Generation Control provisions of this OC6B.
PROCEDURE FOR THE IMPLEMENTATION OF EMBEDDED GENERATION CONTROL ON THE INSTRUCTIONS OF THE COMPANY

OC6B.4.1 A National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction will, where possible, be issued by The Company, as more particularly set out in OC6B.4.4, OC7.4.8 and BC1.5.5 when The Company anticipates that it will or may issue Embedded Generation Control instruction(s).

OC6B.4.2 When The Company anticipates that it will or may issue Embedded Generation Control instruction(s) within the following 30 minutes, The Company will, where possible, issue a National Electricity Transmission System Warning - Embedded Generation Control Imminent in accordance with OC7.4.8.2 and OC7.4.8.11.

OC6B.4.3 (a) Whether a National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction or National Electricity Transmission System Warning – Embedded Generation Control Imminent has been issued or not, each Network Operator will abide by the instructions of The Company and will implement the instructions received in the timescales specified and without delay.

(b) Unless specified otherwise, Embedded Generation Control instructions shall be fulfilled within 30 minutes of an instruction being received from The Company.

OC6B.4.6 Once an Embedded Generation Control instruction has been implemented by a Network Operator, the Network Operator may interchange the Embedded Generators who have been subject to Embedded Generation Control provided that the percentage or volume of Active Power reduction achieved at all times within the Network Operator's System does not change.

OC6B.4.7 An instruction from The Company to the Network Operator will be given to allow the Network Operator to arrange with a Generator owning or operating an Embedded Power Stations subject to Embedded Generation Control to resume normal operation. Such arrangements shall not commence until such an instruction has been received.

OC6B.4.8 Where Embedded Generation Control to manage events within the scope of OC6B is envisaged by The Company to be a prolonged requirement, The Company will notify the Network Operator of the expected duration.

OC6B.4.9 Each Network Operator will notify The Company in writing that it has complied with The Company's instructions under OC6B.5, within five minutes of so doing, together with an estimation of the Active Power output reduction achieved, in MWs, by the Embedded Generation Control.

OC6B.4.10 Each Network Operator will supply to The Company a revised estimate of the Active Power output reduction achieved, in MW, by the use of Embedded Generation Control within 30 minutes of complying with the instruction.

OC6B.5 PRIORITIES FOR IMPLEMENTATION OF EMBEDDED GENERATION CONTROL INSTRUCTIONS

OC6B.5.1 The implementation of an Embedded Generation Control instruction is at the reasonable discretion of each Network Operator to whom an instruction is given by The Company. In implementing an instruction and determining the order in which Embedded Power Stations are affected by it, it is expected that a Network Operator would respect the priority order set out in the table below unless it could be reasonably expected to be aware of other issues that would influence the implementation order including:

a) whether the Embedded Generation Control has been issued following a National Electricity Transmission System Warning – System NRAPM or a National Electricity Transmission System Warning – Localised NRAPM, and therefore any specific local circumstances that it is a requirement to address;
b) the effectiveness of **Embedded Generation Control** actions to address the issues to be resolved;

c) Interactions with other network considerations such as the participation of **Embedded Power Stations** in Active Network Management (ANM) or other automatic switching schemes, or in the provision of other **Ancillary Services**; and

d) any other wider system issues and the potential consequences for **Users**, including environmental and safety concerns, and where applicable taking account of the incidence of such instructions.

All implementation decisions should be reasonable and based on the information available to the **Network Operator** at the time taking into account the leadtime available in the instruction issued by **The Company**

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<th>ORDER</th>
<th>CATEGORY OF GENERATION</th>
<th>COMMENT</th>
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</thead>
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<td>1</td>
<td>Non-synchronous generation</td>
<td>Non-synchronous plant typically does not contribute towards system inertia hence is higher up the list due to the need to maintain system inertia, particularly in the scenario applicable to <strong>Embedded Generation Control</strong> where a very low demand situation coincides with high availability of non-synchronous generation. In the event that any alternatives to system inertia are available this should also be taken into account.</td>
</tr>
<tr>
<td>2</td>
<td>Synchronous generators without any associated demand</td>
<td>Lower down the list due to the need to maintain system inertia, particularly in a very low demand situation.</td>
</tr>
<tr>
<td>3</td>
<td>Generation with associated demand</td>
<td>For example, CHP installations, waste management facilities, and other industrial facilities with substantial on-site demand.</td>
</tr>
<tr>
<td>4</td>
<td>Generation associated with critical national infrastructure sites</td>
<td>Never envisaged to be selected.</td>
</tr>
</tbody>
</table>
OC6B.6  OPERATION OF THE BALANCING MECHANISM DURING EMBEDDED GENERATION CONTROL

Instructions issued by The Company to carry out Embedded Generation Control will constitute Emergency Instructions in accordance with BC2.9 and it may be necessary to depart from normal Balancing Mechanism operation in accordance with BC2 in issuing Bid-Offer Acceptances. The Company will inform affected BM Participants in accordance with the provisions of OC7.
# OPERATING CODE NO. 7  
(OC7)

**OPERATIONAL LIAISON**

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OC7.1 INTRODUCTION

OC7.1.1 Operating Code No. 7 ("OC7") sets out the requirements for the exchange of information in relation to Operations and/or Events on the Total System which have had (or may have had) or will have (or may have) an Operational Effect:

(a) on the National Electricity Transmission System in the case of an Operation and/or Event occurring on the System of a User or Users; and

(b) on the System of a User or Users in the case of an Operation and/or Event occurring on the National Electricity Transmission System.

It also describes the types of National Electricity Transmission System Warning which may be issued by The Company.

OC7.1.2 The requirement to notify in OC7 relates generally to notifying of what is expected to happen or what has happened and not the reasons why. However, as OC7 provides, when an Event or Operation has occurred on the National Electricity Transmission System which itself has been caused by (or exacerbated by) an Operation or Event on a User's System, The Company in reporting the Event or Operation on the National Electricity Transmission System to another User can pass on what it has been told by the first User in relation to the Operation or Event on the first User's System.

OC7.1.3 Where an Event or Operation on the National Electricity Transmission System fails to be reported by The Company to an Externally Interconnected System Operator under an Interconnection Agreement, OC7 provides that in the situation where that Event or Operation has been caused by (or exacerbated by) an Operation or Event on a User's System, The Company can pass on what it has been told by the User in relation to the Operation or Event on that User's System.

OC7.1.4 OC7 also deals with Integral Equipment Tests.

OC7.1.5 To reconfigure the National Electricity Transmission System, The Company may reasonably require the assistance of a User to reconfigure parts of the User System. To reconfigure its User System a User may reasonably require the reasonable assistance of The Company to direct the reconfiguration of parts of the National Electricity Transmission System.

OC7.1.6 OC7.6 sets down the arrangements for the exchange of information required when configuring Connection Sites (or in the case of OTSUA operational prior to the OTSUA Transfer Time, Transmission Interface Sites) and parts of the National Electricity Transmission System adjacent to those Connection Sites (or Transmission Interface Sites) in Scotland and Offshore. It also covers the setting up of a Local Switching Procedure. The Company shall procure that Relevant Transmission Licensees shall comply with section OC7.6 and any relevant Local Switching Procedure where and to the extent that such matters apply to them.

OC7.2 OBJECTIVE

The objectives of OC7 are:

OC7.2.1 To provide for the exchange of information so that the implications of an Operation and/or Event can be considered, possible risks arising from it can be assessed and appropriate action taken by the relevant party in order to maintain the integrity of the Total System. OC7 does not seek to deal with any actions arising from the exchange of information, but merely with that exchange.

OC7.2.2 To provide for types of National Electricity Transmission System Warnings which may be issued by The Company.

OC7.2.3 To provide the framework for the information flow and discussion between The Company and certain Users in relation to Integral Equipment Tests.

OC7.2.4 To provide the procedure to be followed in respect of Operational Switching.
OC7.3 SCOPE

OC7.3.1 OC7 applies to The Company and to Users, which in OC7 means:

(a) Generators (other than those which only have Embedded Small Power Stations or Embedded Medium Power Stations) and including Generators undertaking OTSDUW;

(b) Network Operators;

(c) Non-Embedded Customers;

(d) Suppliers (for the purposes of National Electricity Transmission System Warnings);

(e) Externally Interconnected System Operators (for the purposes of National Electricity Transmission System Warnings); and

(f) DC Converter Station owners and HVDC System Owners.

The procedure for operational liaison by The Company with Externally Interconnected System Operators is set out in the Interconnection Agreement with each Externally Interconnected System Operator.

OC7.6 also applies to Relevant Transmission Licensees.

OC7.4 PROCEDURE

OC7.4.1 The term "Operation" means a scheduled or planned action relating to the operation of a System (including an Embedded Power Station).

OC7.4.2 The term "Event" means an unscheduled or unplanned (although it may be anticipated) occurrence on, or relating to, a System (including an Embedded Power Station) including, without limiting that general description, faults, incidents and breakdowns and adverse weather conditions being experienced.

OC7.4.3 The term "Operational Effect" means any effect on the operation of the relevant other System which causes the National Electricity Transmission System or the Systems 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 normally operated in the absence of that effect.

OC7.4.4 References in this OC7 to a System of a User or User’s System shall not include Embedded Small Power Stations or Embedded Medium Power Stations, unless otherwise stated.

OC7.4.5 Requirement To Notify Operations

OC7.4.5.1 Operation On The National Electricity Transmission System

In the case of an Operation on the National Electricity Transmission System, which will have (or may have) an Operational Effect on the System(s) of a User or Users, The Company will notify the User or Users whose System(s) will, or may, in the reasonable opinion of The Company, be affected, in accordance with OC7.

OC7.4.5.2 Operation On a User's System

In the case of an Operation on the System of a User which will have (or may have) an Operational Effect on the National Electricity Transmission System (including an equivalent to an Operation on the equivalent of a System of a User or other person connected to that User’s System which, via that User System, will or may have an Operational Effect on the National Electricity Transmission System), the User will notify The Company in accordance with OC7. Following notification by the User, The Company will notify any other User or Users on whose System(s) the Operation will have, or may have, in the reasonable opinion of The Company, an Operational Effect, in accordance with OC7 and will notify any Externally Interconnected System Operator on whose System the Operation will have, or may have, in the reasonable opinion of The Company, an Operational Effect, if it is required to do so by the relevant Interconnection Agreement.

OC7.4.5.3 Examples Of Situations Where Notification By The Company Or a User may be Required

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Whilst in no way limiting the general requirement to notify in advance set out in OC7.4.5.1 and OC7.4.5.2, the following are examples of situations where notification in accordance with OC7.4.5 will be required if they will, or may, have an Operational Effect:

(a) the implementation of a planned outage of Plant and/or Apparatus which has been arranged pursuant to OC2;

(b) the operation (other than, in the case of a User, at the instruction of The Company) of any circuit breaker or isolator/disconnector or any sequence or combination of the two; or

(c) voltage control.

OC7.4.5.4 Operations Caused By Another Operation Or By An Event

An Operation may be caused by another Operation or an Event on another’s System (including an Embedded Power Station) (or by the equivalent of an Event or Operation on the System of an Externally Interconnected System Operator or Interconnector User) and in that situation the information to be notified is different to that where the Operation arose independently of any other Operation or Event, as more particularly provided in OC7.4.5.6.

OC7.4.5.5 Form

A notification and any response to any questions asked under OC7.4.5, of an Operation which has arisen independently of any other Operation or of an Event, shall be of sufficient detail to describe the Operation (although it need not state the cause) and to enable the recipient of the notification reasonably to consider and assess the implications and risks arising (provided that, in the case of an Operation on a User’s System which The Company is notifying to other Users under OC7.4.5.2, The Company will only pass on what it has been told by the User which has notified it) and will include the name of the individual reporting the Operation on behalf of The Company or the User, as the case may be. The recipient may ask questions to clarify the notification and the giver of the notification will, insofar as it is able, answer any questions raised, provided that, in the case of an Operation on a User’s System which The Company is notifying to other Users under OC7.4.5.2, in answering any question, The Company will not pass on anything further than that which it has been told by the User which has notified it. The Company may pass on the information contained in the notification as provided in OC7.4.5.6.

OC7.4.5.6 (a) A notification by The Company of an Operation under OC7.4.5.1 which has been caused by another Operation (the “first Operation”) or by an Event on a User’s System, will describe the Operation and will contain the information which The Company has been given in relation to the first Operation or that Event by the User. The notification and any response to any questions asked (other than in relation to the information which The Company is merely passing on from a User) will be of sufficient detail to enable the recipient of the notification reasonably to consider and assess the implications and risks arising from the Operation on the National Electricity Transmission System and will include the name of the individual reporting the Operation on behalf of The Company. The recipient may ask questions to clarify the notification and The Company will, insofar as it is able, answer any questions raised, provided that in relation to the information which The Company is merely passing on from a User, in answering any question The Company will not pass on anything further than that which it has been told by the User which has notified it.

(b) Where a User is reporting an Operation or an Event which itself has been caused by an incident or scheduled or planned action affecting (but not on) its System, the notification to The Company will contain the information which the User has been given by the person connected to its System in relation to that incident or scheduled or planned action (which the User must require, contractually or otherwise, the person connected to its System to give to it) and The Company may pass on the information contained in the notification as provided in this OC7.4.5.6.
Where an **Operation** on the **National Electricity Transmission System** falls to be reported by **The Company** under an **Interconnection Agreement** and the **Operation** has been caused by another **Operation** (the "first **Operation**") or by an **Event** on a **User's System**, **The Company** will include in that report the information which **The Company** has been given in relation to the first **Operation** or that **Event** by the **User** (including any information relating to an incident or scheduled or planned action, as provided in OC7.4.5.6).

### OC7.4.5.8

(a) A notification to a **User** by **The Company** of an **Operation** under OC7.4.5.1 which has been caused by the equivalent of an **Operation** or of an **Event** on the equivalent of a **System** of an **Externally Interconnected System Operator** or **Interconnector User**, will describe the **Operation** on the **National Electricity Transmission System** and will contain the information which **The Company** has been given, in relation to the equivalent of an **Operation** or of an **Event** on the equivalent of a **System** of an **Externally Interconnected System Operator** or **Interconnector User**, by that **Externally Interconnected System Operator** or **Interconnector User**.

(b) The notification and any response to any question asked (other than in relation to the information which **The Company** is merely passing on from that **Externally Interconnected System Operator** or **Interconnector User**) will be of sufficient detail to enable the recipient of the notification reasonably to consider and assess the implications and risks arising from the **Operation** on the **National Electricity Transmission System** and will include the name of the individual reporting the **Operation** on behalf of **The Company**. The recipient may ask questions to clarify the notification and **The Company** will, insofar as it is able, answer any questions raised, provided that, in relation to the information which **The Company** is merely passing on from an **Externally Interconnected System Operator** or **Interconnector User**, in answering any question **The Company** will not pass on anything further than that which it has been told by the **Externally Interconnected System Operator** or **Interconnector User** which has notified it.

### OC7.4.5.9

(a) A **Network Operator** may pass on the information contained in a notification to it from **The Company** under OC7.4.5.1, to a **Generator** with a **Power Generating Module** (including a **DC Connected Power Park Module**), **Generating Unit** or a **Power Park Module** connected to its **System**, or to a **DC Converter Station** owner with a **DC Converter** or to a **HVDC System Owner** with a **HVDC System** connected to its **System**, or to the operator of another **User System** connected to its **System** (which, for the avoidance of doubt, could be another **Network Operator**), in connection with reporting the equivalent of an **Operation** under the **Distribution Code** (or the contract pursuant to which that **Power Generating Module** (including a **DC Connecting Power Generating Module**), and/or **Generating Unit** and/or **Power Park Module** or other **User System**, or to a **DC Converter Station** or to an **HVDC System** is connected to the **System** of that **Network Operator**) (if the **Operation** on the **National Electricity Transmission System** caused it).

(b) A **Generator** may pass on the information contained in a notification to it from **The Company** under OC7.4.5.1, to another **Generator** with a **Power Generating Module** (including a **DC Connected Power Park Module**) and/or **Generating Unit** or a **Power Park Module** connected to its **System**, or to the operator of a **User System** connected to its **System** (which, for the avoidance of doubt, could be a **Network Operator**), if it is required (by a contract pursuant to which that **Power Generating Module** (including a **DC Connected Power Park Module**) and/or **Generating Unit** and/or that **Power Park Module** or that **User System** is connected to its **System**) to do so in connection with the equivalent of an **Operation** on its **System** (if the **Operation** on the **National Electricity Transmission System** caused it).
OC7.4.5.10 (a) Other than as provided in OC7.4.5.9, a Network Operator or a Generator may not pass on any information contained in a notification to it from The Company under OC7.4.5.1 (and an operator of a User System or Generator receiving information which was contained in a notification to a Generator or a Network Operator, as the case may be, from The Company under OC7.4.5.1, as envisaged in OC7.4.5.9 may not pass on this information) to any other person, but may inform persons connected to its System (or in the case of a Generator which is also a Supplier, inform persons to which it supplies electricity which may be affected) that there has been an incident on the Total System, the general nature of the incident (but not the cause of the incident) and (if known and if power supplies have been affected) an estimated time of return to service.

(b) In the case of a Generator which has an Affiliate which is a Supplier, the Generator may inform it that there has been an incident on the Total System, the general nature of the incident (but not the cause of the incident) and (if known and if power supplies have been affected in a particular area) an estimated time of return to service in that area, and that Supplier may pass this on to persons to which it supplies electricity which may be affected).

(c) Each Network Operator and Generator shall use its reasonable endeavours to procure that any Generator or operator of a User System receiving information which was contained in a notification to a Generator or Network Operator, as the case may be, from The Company under OC7.4.5.1, which is not bound by the Grid Code, does not pass on any information other than as provided above.

OC7.4.5.11 The notification will, if either party requests, be recorded by the sender and dictated to the recipient, who shall record and repeat each phrase as it is received and on completion of the dictation shall repeat back the notification in full to the sender who shall confirm that it has been accurately recorded.

OC7.4.5.12 Timing

A notification under OC7.4.5 will be given as far in advance as possible and in any event shall be given in sufficient time as will reasonably allow the recipient to consider and assess the implications and risks arising.

OC7.4.6 Requirements To Notify Events

OC7.4.6.1 Events On The National Electricity Transmission System

In the case of an Event on the National Electricity Transmission System which has had (or may have had) an Operational Effect on the System(s) of a User or Users, The Company will notify the User or Users whose System(s) have been, or may have been, in the reasonable opinion of The Company, affected, in accordance with OC7.

OC7.4.6.2 Events On A User's System

In the case of an Event on the System of a User which has had (or may have had) an Operational Effect on the National Electricity Transmission System, the User will notify The Company in accordance with OC7.

OC7.4.6.3 Events Caused By Another Event Or By An Operation

An Event may be caused (or exacerbated by) another Event or by an Operation on another’s System (including on an Embedded Power Station) (or by the equivalent of an Event or Operation on the equivalent of a System of an Externally Interconnected System Operator or Interconnector User) and in that situation the information to be notified is different to that where the Event arose independently of any other Event or Operation, as more particularly provided in OC7.4.6.7.

OC7.4.6.4 The Company or a User, as the case may be, may enquire of the other whether an Event has occurred on the other’s System. If it has, and the party on whose System the Event has occurred is of the opinion that it may have had an Operational Effect on the System of the party making the enquiry, it shall notify the enquirer in accordance with OC7.

OC7.4.6.5 Examples Of Situations Where Notification By The Company or a User may be Required
Whilst in no way limiting the general requirement to notify set out in OC7.4.6.1, OC7.4.6.2 and OC7.4.6.3, the following are examples of situations where notification in accordance with OC7.4.6 will be required if they have an Operational Effect:

(a) where Plant and/or Apparatus is being operated in excess of its capability or may present a hazard to personnel;

(b) the activation of any alarm or indication of any abnormal operating condition;

(c) adverse weather conditions being experienced;

(d) breakdown of, or faults on, or temporary changes in the capabilities of, Plant and/or Apparatus;

(e) breakdown of, or faults on, control, communication and metering equipment; or

(f) increased risk of inadvertent protection operation.

Form

OC7.4.6.6 A notification and any response to any questions asked under OC7.4.6.1 and OC7.4.6.2 of an Event which has arisen independently of any other Event or of an Operation, will describe the Event, although it need not state the cause of the Event, and, subject to that, will be of sufficient detail to enable the recipient of the notification reasonably to consider and assess the implications and risks arising and will include the name of the individual reporting the Event on behalf of The Company or the User, as the case may be. The recipient may ask questions to clarify the notification and the giver of the notification will, insofar as it is able (although it need not state the cause of the Event) answer any questions raised. The Company may pass on the information contained in the notification as provided in OC7.4.6.7.

OC7.4.6.7 (a) A notification (and any response to any questions asked under OC7.4.6.1) by The Company of (or relating to) an Event under OC7.4.6.1 which has been caused by (or exacerbated by) another Event (the "first Event") or by an Operation on a User's System will describe the Event and will contain the information which The Company has been given in relation to the first Event or that Operation by the User (but otherwise need not state the cause of the Event). The notification and any response to any questions asked (other than in relation to the information which The Company is merely passing on from a User) will be of sufficient detail to enable the recipient of the notification reasonably to consider and assess the implications and risks arising from the Event on the National Electricity Transmission System and will include the name of the individual reporting the Event on behalf of The Company. The recipient may ask questions to clarify the notification and The Company will, insofar as it is able, answer any questions raised, provided that in relation to the information which The Company is merely passing on from a User, in answering any question The Company will not pass on anything further than that which it has been told by the User which has notified it.

(b) Where a User is reporting an Event or an Operation which itself has been caused by (or exacerbated by) an incident or scheduled or planned action affecting (but not on) its System the notification to The Company will contain the information which the User has been given by the person connected to its System in relation to that incident or scheduled or planned action (which the User must require, contractually or otherwise, the person connected to its System to give to it) and The Company may pass on the information contained in the notification as provided in this OC7.4.6.7.

OC7.4.6.8 Where an Event on the National Electricity Transmission System falls to be reported by The Company under an Interconnection Agreement and the Event has been caused by (or exacerbated by) another Event (the "first Event") or by an Operation on a User's System, The Company will include in that report the information which The Company has been given in relation to the first Event or that Operation by the User (including any information relating to an incident or scheduled or planned action on that User's System, as provided in OC7.4.6.7).
OC7.4.6.9  (a) A notification to a User (and any response to any questions asked under OC7.4.6.1) by The Company of (or relating to) an Event under OC7.4.6.1 which has been caused by (or exacerbated by) the equivalent of an Event or of an Operation on the equivalent of a System of an Externally Interconnected System Operator or Interconnector User, will describe the Event on the National Electricity Transmission System and will contain the information which The Company has been given, in relation to the equivalent of an Event or of an Operation on the equivalent of a System of an Externally Interconnected System Operator or Interconnector User, by that Externally Interconnected System Operator or Interconnector User (but otherwise need not state the cause of the Event).

(b) The notification and any response to any questions asked (other than in relation to the information which The Company is merely passing on from that Externally Interconnected System Operator or Interconnector User) will be of sufficient detail to enable the recipient of the notification reasonably to consider and assess the implications and risks arising from the Event on the National Electricity Transmission System and will include the name of the individual reporting the Event on behalf of The Company. The recipient may ask questions to clarify the notification and The Company will, insofar as it is able (although it need not state the cause of the Event) answer any questions raised, provided that, in relation to the information which The Company is merely passing on from an Externally Interconnected System Operator or Interconnector User, in answering any question The Company will not pass on anything further than that which it has been told by the Externally Interconnected System Operator or Interconnector User which has notified it.

OC7.4.6.10 (a) A Network Operator may pass on the information contained in a notification to it from The Company under OC7.4.6.1, to a Generator with a Power Generating Module (including a DC Connected Power Park Module) and/or Generating Unit and/or a Power Park Module connected to its System or to a DC Converter Station owner with a DC Converter or to an HVDC System Owner with an HVDC System connected to its System or to the operator of another User System connected to its System (which, for the avoidance of doubt, could be a Network Operator), in connection with reporting the equivalent of an Event under the Distribution Code (or the contract pursuant to which that Power Generating Module and/or Generating Unit and/or Power Park Module or DC Converter or HVDC System or other User System is connected to the System of that Network Operator) (if the Event on the National Electricity Transmission System caused or exacerbated it).

(b) A Generator may pass on the information contained in a notification to it from The Company under OC7.4.6.1, to another Generator with a Power Generating Module and/or Generating Unit and/or a Power Park Module connected to its System or to the operator of a User System connected to its System (which, for the avoidance of doubt, could be a Network Operator), if it is required (by a contract pursuant to which that Power Generating Module (including a DC Connected Power Park Module) and/or Generating Unit and/or that Power Park Module or that User System is connected to its System) to do so in connection with the equivalent of an Event on its System (if the Event on the National Electricity Transmission System caused or exacerbated it).

OC7.4.6.11 (a) Other than as provided in OC7.4.6.10, a Network Operator or a Generator, may not pass on any information contained in a notification to it from The Company under OC7.4.6.1 (and an operator of a User System or Generator receiving information which was contained in a notification to a Generator or a Network Operator, as the case may be, from The Company under OC7.4.6.1, as envisaged in OC7.4.6.10 may not pass on this information) to any other person, but may inform persons connected to its System (or in the case of a Generator which is also a Supplier, inform persons to which it supplies electricity which may be affected) that there has been an incident on the Total System, the general nature of the incident (but not the cause of the incident) and (if known and if power supplies have been affected) an estimated time of return to service.
(b) In the case of a Generator which has an Affiliate which is a Supplier, the Generator may inform it that there has been an incident on the Total System, the general nature of the incident (but not the cause of the incident) and (if known and if power supplies have been affected in a particular area) an estimated time of return to service in that area, and that Supplier may pass this on to persons to which it supplies electricity which may be affected.

(c) Each Network Operator and Generator shall use its reasonable endeavours to procure that any Generator or operator of a User System receiving information which was contained in a notification to a Generator or Network Operator, as the case may be, from The Company under OC7.4.6.1, which is not bound by the Grid Code, does not pass on any information other than as provided above.

**OC7.4.6.12** When an Event relating to a Power Generating Module and/or Generating Unit and/or a Power Park Module or a DC Converter or an HVDC System (or OTSUA operational prior to the OTSUA Transfer Time), has been reported to The Company by a Generator or DC Converter Station owner or HVDC System Owner under OC7.4.6 and it is necessary in order for the Generator or DC Converter Station owner or HVDC System Owner to assess the implications of the Event on its System more accurately, the Generator or DC Converter Station owner or HVDC System Owner may ask The Company for details of the fault levels from the National Electricity Transmission System to that Power Generating Module and/or Generating Unit and/or Power Park Module or DC Converter or HVDC System (or OTSUA operational prior to the OTSUA Transfer Time) at the time of the Event, and The Company will, as soon as reasonably practicable, give the Generator or DC Converter Station owner or HVDC System Owner that information provided that The Company has that information.

**OC7.4.6.13** Except in an emergency situation the notification of an Event will, if either party requests, be recorded by the sender and dictated to the recipient, who shall record and repeat each phrase as it is received and on completion of the dictation shall repeat the notification in full to the sender who shall confirm that it has been accurately recorded.

**OC7.4.6.14** A notification under OC7.4.6 shall be given as soon as possible after the occurrence of the Event, or time that the Event is known of or anticipated by the giver of the notification under OC7, and in any event within 15 minutes of such time.

**OC7.4.7** Significant Incidents

**OC7.4.7.1** Where a User notifies The Company of an Event under OC7 which The Company considers has had or may have had a significant effect on the National Electricity Transmission System, The Company will require the User to report that Event in writing in accordance with the provisions of OC10 and will notify that User accordingly.

**OC7.4.7.2** Where The Company notifies a User of an Event under OC7 which the User considers has had or may have had a significant effect on that User’s System, that User will require The Company to report that Event in writing in accordance with the provisions of OC10 and will notify The Company accordingly.

**OC7.4.7.3** Events which The Company requires a User to report in writing pursuant to OC7.4.7.1, and Events which a User requires The Company to report in writing pursuant to OC7.4.7.2, are known as “Significant Incidents”.

**OC7.4.7.4** Without limiting the general description set out in OC7.4.7.1 and OC7.4.7.2, a Significant Incident will include Events having an Operational Effect which result in, or may result in, the following:

(a) operation of Plant and/or Apparatus either manually or automatically;

(b) voltage outside statutory limits;

(c) Frequency outside statutory limits; or

(d) System instability.
National Electricity Transmission System Warnings

Role Of National Electricity Transmission System Warnings

National Electricity Transmission System Warnings as described below provide information relating to System conditions or Events and are intended to:

(i) alert Users to possible or actual Plant shortage, System problems and/or Demand or generation Active Power reductions;

(ii) inform of the applicable period;

(iii) indicate intended consequences for Users; and

(iv) enable specified Users to be in a state of readiness to react properly to instructions received from The Company.

A table of National Electricity Transmission System Warnings, set out in Appendix 1 to OC7, summarises the warnings and their usage. In the case of a conflict between the table and the provisions of the written text of OC7, the written text will prevail.

Recipients Of National Electricity Transmission System Warnings

(a) Where National Electricity Transmission System Warnings, (except those relating to Demand Control Imminent and Embedded Generation Control Imminent), are applicable to System conditions or Events which have widespread effect, The Company will notify all Users under OC7.

(b) Where in The Company's judgement System conditions or Events may only have a limited effect, the National Electricity Transmission System Warning will as a minimum only be issued to those Users who are or may in The Company's judgement be affected.

(c) Where a National Electricity Transmission System Warning - Demand Control Imminent is issued it will as a minimum only be sent to those Users who are likely to receive Demand Control instructions from The Company.

(d) Where a National Electricity Transmission System Warning Embedded Generation Control Imminent is issued it will as a minimum only be sent to those Network Operators who are likely to receive Embedded Generation Control instructions.

Preparatory Action

(a) Where possible, and if required, recipients of the warnings should take such preparatory action as they deem necessary taking into account the information contained in the National Electricity Transmission System Warning. All warnings will be of a form determined by The Company and will remain in force from the stated time of commencement until the cancellation, amendment or re-issue, as the case may be, is notified by The Company.

(b) Where a National Electricity Transmission System Warning has been issued to a Network Operator and is current, Demand Control should not (subject as provided below) be employed unless instructed by The Company. If Demand Control is, however, necessary to preserve the integrity of the Network Operator's System, then the impact upon the integrity of the Total System should be considered by the Network Operator and where practicable discussed with The Company prior to its implementation.

Where a National Electricity Transmission System Warning has been issued to a Supplier, further Customer Demand Management (in addition to that previously notified under OC1 - Demand Forecasts) must only be implemented following notification to The Company.
(c) **National Electricity Transmission System Warnings** will be issued by such data transmission facilities as have been agreed between The Company and Users. In the case of Generators with Gensets this will normally be at their Trading Points (if they have notified The Company that they have a Trading Point).

(d) Users may at times be informed by telephone of **National Electricity Transmission System Warnings** and in these circumstances confirmation will be sent to those Users so notified by such data transmission facilities as have been agreed between The Company and Users, as soon as possible.

**OC7.4.8.4 Types Of National Electricity Transmission System Warnings**

National Electricity Transmission System Warnings consist of the following types:

(i) National Electricity Transmission System Warning - Electricity Margin Notice

(ii) National Electricity Transmission System Warning - High Risk of Demand Reduction

(iii) National Electricity Transmission System Warning - Demand Control Imminent

(iv) National Electricity Transmission System Warning – System NRAPM

(v) National Electricity Transmission System Warning – Localised NRAPM

(vi) National Electricity Transmission System Warning – High Risk of Embedded Generation Reduction

(vii) National Electricity Transmission System Warning - Embedded Generation Control Imminent

(viii) National Electricity Transmission System Warning - Risk of System Disturbance

**OC7.4.8.5 National Electricity Transmission System Warning - Electricity Margin Notice**

A **National Electricity Transmission System Warning - Electricity Margin Notice** may be issued to Users in accordance with OC7.4.8.2, at times when there is a reduced System Margin, as determined under BC1.5.4. It will contain the following information:

(i) the period for which the warning is applicable; and

(ii) the availability shortfall in MW; and

(iii) intended consequences for Users, including notification that Maximum Generation Service may be instructed.

**OC7.4.8.6 National Electricity Transmission System Warning - High Risk of Demand Reduction**

(a) A **National Electricity Transmission System Warning - High Risk of Demand Reduction** may be issued to Users in accordance with OC7.4.8.2 at times when there is a reduced System Margin, as determined under BC1.5.4 and in The Company's judgement there is increased risk of Demand reduction being implemented under OC6.5.1. It will contain the following information in addition to the required information in a National Electricity Transmission System Warning - Electricity Margin Notice:

(i) the possible percentage level of Demand reduction required; and

(ii) Specify those Network Operators and Non Embedded Customers who may subsequently receive instructions under OC6.5.1.

(b) A **National Electricity Transmission System Warning - High Risk of Demand Reduction** may also be issued by The Company to those Network Operators and Non Embedded Customers who may subsequently receive instructions under OC6.5.1 relating to a Demand reduction in circumstances not related to System Margin (for example Demand reduction required to manage System overloading).

The **National Electricity Transmission System Warning - High Risk of Demand Reduction** will specify the period during which Demand reduction may be required and the part of the Total System to which it applies and any other matters specified in OC6.5.
OC7.4.8.6.1 Protracted Periods Of Generation Shortage

(a) Whenever The Company anticipates that a protracted period of generation shortage may exist a National Electricity Transmission System Warning - Electricity Margin Notice or High Risk of Demand Reduction may be issued, to give as much notice as possible to those Network Operators and Non Embedded Customers who may subsequently receive instructions under OC6.5.

(b) A National Electricity Transmission System Warning - High Risk of Demand Reduction will in these instances include an estimate of the percentage of Demand reduction that may be required and the anticipated duration of the Demand reduction. It may also include information relating to estimates of any further percentage of Demand reduction that may be required.

(c) The issue of the National Electricity Transmission System Warning - Electricity Margin Notice or High Risk of Demand Reduction is intended to enable recipients to plan ahead on the various aspects of Demand reduction.

OC7.4.8.7 National Electricity Transmission System Warning - Demand Control Imminent

(a) A National Electricity Transmission System Warning - Demand Control Imminent, relating to a Demand reduction under OC6.5, will be issued by The Company to Users in accordance with OC7.4.8.2. It will specify those Network Operators who may subsequently receive instructions under OC6.5.

(b) A National Electricity Transmission System Warning - Demand Control Imminent, need not be preceded by any other National Electricity Transmission System Warning and will be issued when a Demand reduction is expected within the following 30 minutes, but will not cease to have effect after 30 minutes from its issue. However, The Company will either reissue the National Electricity Transmission System Warning - Demand Control Imminent or cancel the National Electricity Transmission System Warning - Demand Control Imminent no later than 2 hours from first issue, or from re-issue, as the case may be.

OC7.4.8.8 National Electricity Transmission System Warning – System NRAPM

(a) Procedures for maintaining System NRAPM are defined in BC1.5.5 but where this is, in the view of The Company and as set out in BC1.5.5, deemed likely to be insufficient this will be communicated to all Users and will be treated as a System Warning.

(b) Such a System Warning will where possible include information on the likely reduction in Active Power that will be required and the timing and duration of this.

(c) A System NRAPM refers to the margin of Active Power across the whole System.

OC7.4.8.9 National Electricity Transmission System Warning – Localised NRAPM

(a) Procedures for maintaining Localised NRAPM are defined in BC1.5.5 but where this is, in the view of The Company and as set out in BC1.5.5, deemed likely to be insufficient this will be communicated to all Users and will be treated as a System Warning.

(b) Such a System Warning will where possible include information on the likely reduction in Active Power that will be required and the timing and duration of this.

(c) A Localised NRAPM refers to the management of transfers to and from a System Constraint Group.
OC 7.4.8.10 National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction

(a) A National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction may be issued to Users in accordance with OC7.4.8.2 at times when in The Company’s judgement there is increased risk of Embedded Generation Control being required as defined in OC6B.5.

(b) In addition to any information communicated through a System NRAPM or Localised NRAPM, the National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction will specify the period during which Embedded Generation Control may be required and the part of the Total System to which it applies and any other matters specified in OC6B.5.

(c) The issue of the National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction is intended to enable recipients to plan ahead on the various aspects of Embedded Generation Control.

OC7.4.8.11 National Electricity Transmission System Warning – Embedded Generation Control Imminent

(a) A National Electricity Transmission System Warning – Embedded Generation Control Imminent will be issued by The Company to Users in accordance with OC7.4.8.2. It will specify those Network Operators who may subsequently receive instructions under OC6B.5.

(b) A National Electricity Transmission System Warning – Embedded Generation Control Imminent, need not be preceded by any other National Electricity Transmission System Warning and will be issued when an Embedded Generation Control instruction is expected within the following 30 minutes, but will not cease to have effect after 30 minutes from its issue. However, The Company will either reissue the National Electricity Transmission System Warning – Embedded Generation Control Imminent or cancel the National Electricity Transmission System Warning – Embedded Generation Control Imminent no later than 2 hours from first issue, or from re-issue, as the case may be.

OC7.4.8.12 National Electricity Transmission System Warning - Risk of System Disturbance

(a) A National Electricity Transmission System Warning - Risk of System Disturbance will be issued by The Company to Users who may be affected when The Company knows there is a risk of widespread and serious disturbance to the whole or part of, the National Electricity Transmission System;

(b) The National Electricity Transmission System Warning - Risk of System Disturbance will contain such information as The Company deems appropriate;

(c) For the duration of the National Electricity Transmission System Warning - Risk of System Disturbance, each User in receipt of the National Electricity Transmission System Warning - Risk of System Disturbance shall take the necessary steps to warn its operational staff and to maintain its Plant and/or Apparatus in the condition in which it is best able to withstand the anticipated disturbance;

(d) During the period that the National Electricity Transmission System Warning - Risk of System Disturbance is in effect, The Company may issue Emergency Instructions in accordance with BC2 and it may be necessary to depart from normal Balancing Mechanism operation in accordance with BC2 in issuing Bid-Offer Acceptances.

OC7.4.8.13 Cancellation of National Electricity Transmission System Warning

(a) The Company will give notification of a Cancellation of National Electricity Transmission System Warning to all Users issued with the National Electricity Transmission System Warning when in The Company’s judgement System conditions have returned to normal.
(b) A Cancellation of National Electricity Transmission System Warning will identify the type of National Electricity Transmission System Warning being cancelled and the period for which it was issued. The Cancellation of National Electricity Transmission System Warning will also identify any National Electricity Transmission System Warnings that are still in force.

OC7.4.8.14 General Management of National Electricity Transmission System Warnings

(a) National Electricity Transmission System Warnings remain in force for the period specified unless superseded or cancelled by The Company.

(b) A National Electricity Transmission System Warning issued for a particular period may be superseded by further related warnings. This will include National Electricity Transmission System Warning - Electricity Margin Notice being superseded by National Electricity Transmission System Warning - High Risk of Demand Reduction and vice-versa, and National Electricity Transmission System Warning – System NRAPM being superseded by National Electricity Transmission System Warning - High Risk of Embedded Generation Reduction.

(c) In circumstances where it is necessary for the period of a National Electricity Transmission System Warning to be changed:

   (i) the period applicable may be extended by the issue of a National Electricity Transmission System Warning with a period which follows on from the original period, or

   (ii) revised or updated National Electricity Transmission System Warnings will be issued where there is an overlap with the period specified in an existing National Electricity Transmission System Warning, but only if the revised period also includes the full period of the existing National Electricity Transmission System Warning.

In any other case the existing National Electricity Transmission System Warning will be cancelled and a new one issued.

(c) A National Electricity Transmission System Warning is no longer applicable once the period has passed and to confirm this The Company will issue a Cancellation of National Electricity Transmission System Warning.

OC7.4.8.15 Publication of Other System Alerts and Warnings

(a) All instructions, warnings, alerts and notifications upon being received or issued by The Company (whether activating or deactivating an action) as per Appendix 2 of OC7 will be published on the BMRS. Should the BMRS be unavailable, for example due to communications or systems failures, other appropriate channels including email will be utilised until the BMRS can be restored.

(b) The Company will employ reasonable endeavours to publish such information within 15 minutes of issue or receipt, or if not possible within as short a time as is reasonably practicable.

OC7.5 PROCEDURE IN RELATION TO INTEGRAL EQUIPMENT TESTS

OC7.5.1 This section of the Grid Code deals with Integral Equipment Tests. It is designed to provide a framework for the exchange of relevant information and for discussion between The Company and certain Users in relation to Integral Equipment Tests.

OC7.5.2 An Integral Equipment Test:

(a) is carried out in accordance with the provisions of this OC7.5 at:

   (i) a User Site,

   (ii) a Transmission Site,

   (iii) an Embedded Large Power Station, or,
(iv) an Embedded DC Converter Station; or
(v) an Embedded HVDC System

(b) will normally be undertaken during commissioning or re-commissioning of Plant and/or Apparatus;

(c) may, in the reasonable judgement of the person wishing to perform the test, cause, or have the potential to cause, an Operational Effect on a part or parts of the Total System but which with prior notice is unlikely to have a materially adverse effect on any part of the Total System; and

(d) may form part of an agreed programme of work.

In the case of OTSUA operation prior to the OTSUA Transfer Time, a User’s Site or Transmission Site shall, for the purposes of this OC7, include a site at which there is an Interface Point until the OTSUA Transfer Time and the provisions of this OC7.5 and references to OTSUA shall be construed and applied accordingly until the OTSUA Transfer Time.

OC7.5.3
A set of guidance notes is available from The Company on request, which provide further details on suggested procedures, information flows and responsibilities.

Notification Of An IET

OC7.5.4
In order to undertake an Integral Equipment Test (and subject to OC7.5.8 below), the User or The Company, as the case may be, (the proposer) must notify the other (the recipient) of a proposed IET. Reasonable advance notification must be given, taking into account the nature of the test and the circumstances which make the test necessary. This will allow recipients time to adequately assess the impact of the IET on their System.

OC7.5.5
The notification of the IET must normally include the following information:-

(a) the proposed date and time of the IET;

(b) the name of the individual and the organisation proposing the IET;

(c) a proposed programme of testing; and

(d) such further detail as the proposer reasonably believes the recipient needs in order to assess the effect the IET may have on relevant Plant and/or Apparatus.

OC7.5.6
In the case of an IET in connection with commissioning or re-commissioning, the test should be incorporated as part of any overall commissioning programme agreed between The Company and the User.

Response To Notification of an IET

OC7.5.7
The recipient of notification of an IET must respond within a reasonable timescale prior to the start time of the IET and will not unreasonably withhold or delay acceptance of the IET proposal.

OC7.5.8
(a) Where The Company receives notification of a proposed IET from a User, The Company will consult those other Users whom it reasonably believes may be affected by the proposed IET to seek their views. Information relating to the proposed IET may be passed on by The Company with the prior agreement of the proposer. However it is not necessary for The Company to obtain the agreement of any such User as IETs should not involve the application of irregular, unusual or extreme conditions. The Company may however consider any comments received when deciding whether or not to agree to an IET.

(b) In the case of an Embedded Large Power Station or Embedded DC Converter Station, or Embedded HVDC System, the Generator or DC Converter Station owner or HVDC System Owner as the case may be, must liaise with both The Company and the relevant Network Operator. The Company will not agree to an IET relating to such Plant until the Generator or DC Converter Station owner or HVDC System Owner has shown that it has the agreement of the relevant Network Operator.
(c) A Network Operator will liaise with The Company as necessary in those instances where it is aware of an Embedded Small Power Station or an Embedded Medium Power Station which intends to perform tests which in the reasonable judgement of the Network Operator may cause an Operational Effect on the National Electricity Transmission System.

OC7.5.9 The response from the recipient, following notification of an IET must be one of the following:

(a) to accept the IET proposal;

(b) to accept the IET proposal conditionally subject to minor modifications such as date and time;

(c) not to agree the IET, but to suggest alterations to the detail and timing of the IET that are necessary to make the IET acceptable.

Final Confirmation Of an IET

OC7.5.10 The date and time of an IET will be confirmed between The Company and the User, together with any limitations and restrictions on operation of Plant and/or Apparatus.

OC7.5.11 The IET may subsequently be amended following discussion and agreement between The Company and the User.

Carrying Out an IET

OC7.5.12 IETs may only take place when agreement has been reached and must be carried out in accordance with the agreed programme of testing.

OC7.5.13 The implementation of an IET will be notified in accordance with OC7.4.5.

OC7.5.14 Where elements of the programme of testing change during the IET, there must be discussion between the appropriate parties to identify whether the IET should continue.

OC7.6 PROCEDURE IN RESPECT OF OPERATIONAL SWITCHING

OC7.6.1 This section OC7.6 of the Grid Code sets out the procedure to be followed for Operational Switching. Its provisions are supplementary to the provisions of the rest of this OC7.

It is designed to set down the arrangements for The Company, Users and the Relevant Transmission Licensees in respect of the Operational Switching of Plant and Apparatus at a Connection Site and parts of the National Electricity Transmission System adjacent to that Connection Site.

OC7.6.2 In general:

(i) The Company is responsible for directing the configuration of the National Electricity Transmission System

(ii) Each Relevant Transmission Licensee is responsible for the instruction and operation of its Plant and Apparatus on its Transmission System.

(iii) Each User is responsible for the configuration, instruction and operation of its Plant and Apparatus.

Definitive schedules of these responsibilities for each Connection Site are contained in the relevant Site Responsibility Schedules.

For the avoidance of doubt, where a User operates Transmission Plant and Apparatus on behalf of a Relevant Transmission Licensee, The Company cannot instruct the User to operate that Plant and Apparatus.

Planned Operational Switching
OC7.6.3 Following the notification of an Operation under OC7.4.5, The Company and the User shall discuss the Operational Switching required. The Company will then discuss and agree the details of the Operational Switching with the Relevant Transmission Licensee. The Relevant Transmission Licensee shall then make contact with the User to initiate the Operational Switching. For the avoidance of doubt, from the time that the Relevant Transmission Licensee makes contact with the User, the Relevant Transmission Licensee shall then become the primary point of operational contact with the User in relation to OC7 for matters which would or could affect, or would or could be affected by the Operational Switching.

OC7.6.4 The User shall be advised by the Relevant Transmission Licensee on the completion of the Operational Switching, that The Company shall again become the primary point of operational contact for the User in relation to OC7.

OC7.6.5 During Operational Switching, either the Relevant Transmission Licensee or the User may need to unexpectedly terminate the Operational Switching. The Company may also need to terminate the Operational Switching during the Operational Switching. In the event of unexpected termination of the Operational Switching, The Company shall become the primary point of operational contact for the User in relation to OC7. Following the termination of the Operational Switching, it will not be permitted to restart that Operational Switching without the parties again following the process described in OC7.6.3.

Emergencies

OC7.6.6 For Operations and/or Events that present an immediate hazard to the safety of personnel, Plant or Apparatus, the Relevant Transmission Licensee may:

(i) as permitted by the STC, carry out Operational Switching of Plant and Apparatus on its Transmission System without reference to The Company and the User, and

(ii) request a User to carry out Operational Switching without the User first receiving notification from The Company.

In such emergency circumstances, communication between the Relevant Transmission Licensee and the User shall normally be by telephone and will include an exchange of names. The User shall use all reasonable endeavours to carry out Operational Switching on its Plant and Apparatus without delay. Following completion of the requested Operational Switching, the Relevant Transmission Licensee shall notify The Company of the Operational Switching which has taken place. In such emergency circumstances, the User may only refuse to carry out Operational Switching on safety grounds (relating to personnel or plant) and this must be notified to the Relevant Transmission Licensee immediately by telephone.

OC7.6.7 For Operations and/or Events that present an immediate hazard to the safety of personnel, Plant or Apparatus, and which require Operational Switching of Plant or Apparatus on a Transmission System in order to remove the hazard, the User should contact the Relevant Transmission Licensee directly to request Operational Switching of Plant or Apparatus on its Transmission System.

In such emergency circumstances, communication between the Relevant Transmission Licensee and the User shall normally be by telephone and will include an exchange of names. The Relevant Transmission Licensee shall use all reasonable endeavours to carry out Operational Switching on its Plant and Apparatus without delay. Following completion of the requested Operational Switching, the User shall notify The Company of the Operational Switching which has taken place. In such emergency circumstances, the Relevant Transmission Licensee may only refuse to carry out Operational Switching on safety grounds (relating to personnel or plant) and this must be notified to the User immediately by telephone.

OC7.6.8 Establishment Of A Local Switching Procedure

(a) The Company, a User or a Relevant Transmission Licensee may reasonably require a Local Switching Procedure to be established.
(b) Where the need for a Local Switching Procedure arises the following provisions shall apply:

(i) The Company, User(s) and the Relevant Transmission Licensee will discuss and agree the detail of the Local Switching Procedure as soon as the requirement for a Local Switching Procedure is identified. The Company will notify the Relevant Transmission Licensee and the affected User(s) and will initiate these discussions.

(ii) Each Local Switching Procedure shall be in relation to either one or more Connection Sites (or in the case of OTSUA operational prior to the OTSUA Transfer Time, Transmission Interface Sites) and parts of the National Electricity Transmission System adjacent to the Connection Site(s) (or in the case of OTSUA operational prior to the OTSUA Transfer Time, Transmission Interface Sites).

(iii) A draft Local Switching Procedure shall be prepared by the Relevant Transmission Licensee to reflect the agreement reached and shall be sent to The Company.

(iv) When a Local Switching Procedure has been prepared, it shall be sent by The Company to the Relevant Transmission Licensee and User(s) for confirmation of its accuracy.

(v) The Local Switching Procedure shall then be signed on behalf of The Company and on behalf of each User and Relevant Transmission Licensee by way of written confirmation of its accuracy.

(vi) Once agreed under this OC7.6.8, the procedure will become a Local Switching Procedure under the Grid Code, and (subject to any change pursuant to this OC7) will apply between The Company, Relevant Transmission Licensee and the relevant User(s) as if it were part of the Grid Code.

(vii) Once signed, The Company will send a copy of the Local Switching Procedure to the Relevant Transmission Licensee and the User(s).

(viii) An agreed Local Switching Procedure should be referenced by relevant Site Responsibility Schedules.

(ix) The Company, the User(s) and the Relevant Transmission Licensee must make the Local Switching Procedure readily available to the relevant operational staff.

(x) If the Relevant Transmission Licensee or the User(s) become aware that a change is needed to a Local Switching Procedure, they must inform The Company immediately. Where The Company has been informed of a need for a change, or The Company proposes a change, The Company shall notify both the affected User and the Relevant Transmission Licensee and will initiate discussions to agree a change to the Local Switching Procedure. The principles applying to the establishment of a new Local Switching Procedure shall then apply to the discussion and agreement of any changes.
<table>
<thead>
<tr>
<th>WARNING TYPE</th>
<th>GRID CODE</th>
<th>FORMAT</th>
<th>TO: FOR ACTION</th>
<th>TO: FOR INFORMATION</th>
<th>TIMESCALE</th>
<th>WARNING OF FOR CONSEQUENCE</th>
<th>RESPONSE FROM RECIPIENTS</th>
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</thead>
<tbody>
<tr>
<td>National Electricity Transmission System Warning – System NRAPM</td>
<td>OC7.4.8.8</td>
<td>Issued via data transmission facilities and, in some cases, by telephone.</td>
<td>Network Operators</td>
<td>All Users</td>
<td>All timescales when at the time there is not a high risk of Embedded Generation reduction.</td>
<td>Insufficient margin of Active Power available to allow the largest loss of Load at any time. Notification that if not improved Embedded Generation Control may be instructed.</td>
<td>Offers of reduced Active Power infed from Generators or DC Converter Station owners, HVDC System Owners and Interconnector Users. Generators notify The Company of any reduction in Active Power output that they will initiate.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – Localised NRAPM</td>
<td>OC7.4.8.9</td>
<td>Issued via data transmission facilities and, in some cases, by telephone.</td>
<td>Network Operators</td>
<td>All Users</td>
<td>All timescales when at the time there is not a high risk of Embedded Generation reduction.</td>
<td>Insufficient Active Power available to allow transfers to and from a System Constraint Group. Notification that if not improved Embedded Generation Control may be instructed.</td>
<td>Offers of reduced Active Power infed in impacted System Constraint Group from Generators or DC Converter Station owners, HVDC System Owners and Interconnector Users. Generators notify The Company of any reduction in Active Power output that they will initiate.</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – High Risk of Embedded Generation Reduction</td>
<td>OC7.4.8.10</td>
<td>Issued via data transmission facilities and, in some cases, by telephone.</td>
<td>Network Operators</td>
<td>All Users</td>
<td>All timescales when at the time there is not a high risk of Embedded Generation reduction.</td>
<td>Insufficient System NRAPM or Localised NRAPM available and/or a high risk of Embedded Generation Control being instructed.</td>
<td>Offers of reduced Active Power infed from Generators or DC Converter Station owners, HVDC System Owners and Interconnector Users. Generators notify The Company of any reduction in Active Power output that they will initiate. Specified Network Operators to prepare for Embedded Generation Control actions as</td>
</tr>
<tr>
<td>National Electricity Transmission System Warning – Embedded Generation Control Imminent</td>
<td>OC7.4.8.11</td>
<td>Issued via data transmission facilities and, in some cases, by telephone.</td>
<td>Network Operators</td>
<td>All Users</td>
<td>Within 30 minutes of anticipated instruction.</td>
<td>Possibility of Embedded Generation Control within 30 Minutes</td>
<td>Network Operators specified to prepare to take action as necessary to enable them to comply with any subsequent instruction from The Company for Embedded Generation Control.</td>
</tr>
<tr>
<td>WARNING TYPE</td>
<td>GRID CODE</td>
<td>FORMAT</td>
<td>TO: FOR INFORMATION</td>
<td>TIMESCALE</td>
<td>WARNING OF/OR CONSEQUENCE</td>
<td>RESPONSE FROM RECIPIENTS</td>
<td></td>
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</tbody>
</table>
| NATIONAL ELECTRICITY TRANSMISSION WARNING – ELECTRICITY MARGIN NOTICE | OC7.4.8.5 | Fax or other electronic means | Network Operators, Non-Embedded Customers | All timescales when at the time there is not a high risk of Demand reduction. Primarily 1200 hours onwards for a future period. | Insufficient generation available to meet forecast Demand plus Operating Margin. Notification that if not improved Demand reduction may be instructed. (Normal initial warning of insufficient System Margin) | Offers of increased availability from Generators or HVDC System Owners, and Interconnector Users.
Suppliers notify The Company of any additional Customer Demand Management that they will initiate. |

| NATIONAL ELECTRICITY TRANSMISSION SYSTEM WARNING – High risk of Demand Reduction | OC7.4.8.6 | Fax or other electronic means | Network Operators, Non-Embedded Customers, Externally Interconnected System Operators, DC Converter Station Owners, HVDC System Owners | All timescales where there is a high risk of Demand Reduction. Primarily 1200 hours onwards for a future period | Insufficient generation available to meet forecast Demand plus Operating Margin and/or a high risk of Demand Reduction being instructed. (May be issued locally as demand reduction risk only for circuit overloads) | Offers of increased availability from Generators or HVDC System Owners, and Interconnector Users.
Suppliers notify The Company of any additional Customer Demand Management that they will initiate. Specified Network Operators and Non-Embedded Customers to prepare their Demand Reduction arrangements and take actions as necessary to enable compliance with The Company instructions that may follow. (Percentages of Demand Reduction above 20% may not be achieved if The Company has not issued the warning by 16:00 hours the previous day.) |

| NATIONAL ELECTRICITY TRANSMISSION SYSTEM WARNING – Demand Control Imminent | OC7.4.8.7 | Fax/Telephone or other electronic means | None | Within 30 minutes of anticipated instruction | Possibility of Demand Reduction within 30 minutes | Network Operators specified to prepare to take action as necessary to enable them to comply with any subsequent The Company instruction for Demand reduction. |

| NATIONAL ELECTRICITY TRANSMISSION SYSTEM WARNING – Risk of System Disturbance | OC7.4.8.12 | Fax/Telephone or other electronic means | Suppliers | Control room time scales | Risk of widespread system disturbance to whole or part of the National Electricity Transmission System | Recipients take steps to warn operational staff and maintain plant or apparatus such that they are best able to withstand the disturbance. |
## APPENDIX 2 – Other System Alerts and Warnings per OC7.4.8.15

<table>
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<th>Alert Instruction, Notification or Warning Type</th>
<th>Reference</th>
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<td>Demand Disconnection Applied</td>
<td>Demand Control by Demand Disconnection Instructed by The Company</td>
<td>Grid Code O6.5</td>
</tr>
<tr>
<td>Demand Reduction Applied</td>
<td>Demand Control by Voltage Reduction Instructed by the Company</td>
<td>Grid Code O6.5</td>
</tr>
<tr>
<td>Automatic Demand Disconnection Applied</td>
<td>Automatic Low Frequency Demand Disconnection Instructed by the Company</td>
<td>Grid Code O6.6</td>
</tr>
<tr>
<td>Network Operator Demand Control Activated</td>
<td>Network Operator Demand Control Instruction(s) issued.</td>
<td>Grid Code O6.4 and DOC6.6</td>
</tr>
<tr>
<td>Emergency Instructions(s) issued.</td>
<td>Emergency Instruction(s) issued to Network Operator(s)</td>
<td>Grid Code BC2.9.1.4</td>
</tr>
<tr>
<td>Emergency Instruction(s) issued.</td>
<td>Emergency Instruction(s) issued to Generators &amp; Demand Control Operators</td>
<td>Grid Code BC2.9.1.3</td>
</tr>
<tr>
<td>Emergency Instruction(s) issued.</td>
<td>Emergency Instruction(s) issued to Interconnectors</td>
<td>Grid Code BC2.9.1.4</td>
</tr>
<tr>
<td>May require departure from normal Balancing Market Operation in accordance with BC2.</td>
<td>May require departure from normal Balancing Market Operation in accordance with BC2.</td>
<td>Grid Code BC2.9.1.4</td>
</tr>
<tr>
<td>Inadequate Negative Reserve Active Power Margin (nationally)</td>
<td>Inadequate Negative Reserve Active Power Margin (nationally)</td>
<td>Grid Code BC2.9.1.4</td>
</tr>
<tr>
<td>Noted warning no longer applicable.</td>
<td>Noted warning no longer applicable.</td>
<td>Grid Code BC2.9.1.4</td>
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¹Identification of the specific equipment affected is not required to be included within the published alert.
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(OC8)  
SAFETY CO-ORDINATION  
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OC8.1 INTRODUCTION

OC8.1.1 OC8 specifies the standard procedures to be used for the co-ordination, establishment and maintenance of necessary Safety Precautions when work is to be carried out on or near the National Electricity Transmission System or the System of a User and when there is a need for Safety Precautions on HV Apparatus on the other System for this work to be carried out safely. OC8 Appendix 1 applies when work is to be carried out on or near to E&W Transmission Systems or the Systems of E&W Users and OC8 Appendix 2 applies when work is to be carried out on or near to Scottish Transmission Systems or the Systems of Scottish Users.

OC8.1.2 OC8 also covers the co-ordination, establishment and maintenance of necessary safety precautions on the Implementing Safety Co-ordinator’s System when work is to be carried out at a User’s Site or a Transmission Site (as the case may be) on equipment of the User or a Relevant Transmission Licensee as the case may be where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System.

OC8.2 OBJECTIVE

OC8.2.1 The objective of OC8 is to achieve:

(i) Safety From The System when work on or near a System necessitates the provision of Safety Precautions on another System on HV Apparatus up to a Connection Point; and

(ii) Safety From The System when work is to be carried out at a User’s Site or a Transmission Site (as the case may be) on equipment of the User or a Relevant Transmission Licensee (as the case may be) where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System.

OC8.3 SCOPE

OC8.3.1 OC8 applies to The Company and to Users, which in OC8 means:

(a) Generators (including where undertaking OTSDUW);

(b) Network Operators; and

(c) Non-Embedded Customers.

OC8 also applies to Relevant Transmission Licensees.

The procedures for the establishment of safety co-ordination by The Company in relation to External Interconnections are set out in Interconnection Agreements with relevant persons for the External Interconnections.

OC8.4 PROCEDURE

OC8.4.1 Safety Co-Ordination In Respect Of The E&W Transmission Systems Or The Systems Of E&W Users

OC8.4.1.1 OC8 Appendix 1, OC8A, applies when work is to be carried out on or near to the E&W Transmission System or the Systems of E&W Users or when Safety Precautions are required to be established on the E&W Transmission System or the Systems of E&W Users when work is to be carried out on or near to the Scottish Transmission System or the Systems of Scottish Users.
OC8.4.2  Safety Co-Ordination In Respect Of The Scottish Transmission Systems Or The Systems Of Scottish Users

OC8.4.2.1  OC8 Appendix 2, OC8B, applies when work is to be carried out on or near to the Scottish Transmission System or the Systems of Scottish Users or when Safety Precautions are required to be established on the Scottish Transmission System or the Systems of Scottish Users when work is to be carried out on or near to the E&W Transmission System or the Systems of E&W Users.

OC8.4.3  Safety Co-ordination Offshore

OC8.4.3.1  For the purposes of OC8 Appendix 1, OC8A, OC8 Appendix 2 and OC8B, when work is to be carried out on or near to Offshore Transmission Systems Safety Precautions shall be established by the Offshore Transmission Licensee and the Offshore User.

< END OF OPERATING CODE NO. 8 >
## OPERATING CODE NO. 8 APPENDIX 1
### (OC8A)

### SAFETY CO-ORDINATION IN RESPECT OF THE E&W TRANSMISSION SYSTEMS OR THE SYSTEMS OF E&W USERS

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INTRODUCTION

OC8A.1 OC8A specifies the standard procedures to be used by the Relevant E&W Transmission Licensee, The Company and E&W Users for the co-ordination, establishment and maintenance of necessary Safety Precautions when work is to be carried out on or near the E&W Transmission System or the System of an E&W User and when there is a need for Safety Precautions on HV Apparatus on the other’s System for this work to be carried out safely. OC8A applies to Relevant E&W Transmission Licensees and E&W Users only. Where work is to be carried out on or near equipment on the Scottish Transmission System or Systems of Scottish Users, but such work requires Safety Precautions to be established on the E&W Transmission System or the Systems of E&W Users, OC8A should be followed by the Relevant E&W Transmission Licensee and E&W Users to establish the required Safety Precautions.

OC8B specifies the procedures to be used by the Relevant Scottish Transmission Licensees and Scottish Users.

The Company shall procure that the Relevant E&W Transmission Licensees shall comply with OC8A where and to the extent that such section applies to them.

In this OC8A the term “work” includes testing, other than System Tests which are covered by OC12.

OC8A.1.2 OC8A also covers the co-ordination, establishment and maintenance of necessary safety precautions on the Implementing Safety Co-ordinator’s System when work is to be carried out at an E&W User’s Site or a Transmission Site (as the case may be) on equipment of the E&W User or the Relevant E&W Transmission Licensee as the case may be where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System. In the case of OTSUA, an E&W User’s Site or Transmission Site shall, for the purposes of this OC8A, include a site at which there is a Transmission Interface Point until the OTSUA Transfer Time and the provisions of this OC8A and references to OTSUA shall be construed and applied accordingly until the OTSUA Transfer Time at which time arrangements in respect of the Transmission Interface Site will have been put in place between the Relevant E&W Transmission Licensee and the Offshore Transmission Licensee.

OC8A.1.3 OC8A does not apply to the situation where Safety Precautions need to be agreed solely between E&W Users. OC8A does not apply to the situation where Safety Precautions need to be agreed solely between Transmission Licensees.

OC8A.1.4 OC8A does not seek to impose a particular set of Safety Rules on the Relevant E&W Transmission Licensee and E&W Users; the Safety Rules to be adopted and used by the Relevant E&W Transmission Licensee and each E&W User shall be those chosen by each.

OC8A.1.5 Site Responsibility Schedules document the control responsibility for each item of Plant and Apparatus for each site.

OC8A.1.6 Defined Terms

OC8A.1.6.1 E&W Users should bear in mind that in OC8 only, in order that OC8 reads more easily with the terminology used in certain Safety Rules, the term "HV Apparatus" is defined more restrictively and is used accordingly in OC8A. E&W Users should, therefore, exercise caution in relation to this term when reading and using OC8A.

OC8A.1.6.2 In OC8A only the following terms shall have the following meanings:

1) "HV Apparatus" means High Voltage electrical circuits forming part of a System, on which Safety From The System may be required or on which Safety Precautions may be applied to allow work to be carried out on a System.

2) "Isolation" means the disconnection of Apparatus from the remainder of the System in which that 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** of the Relevant E&W Transmission Licensee or that E&W 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** of the Relevant E&W Transmission Licensee or that E&W User, as the case may be, and, if it is a part of that method, a **Caution Notice** must be placed at the point of separation;

or

(c) in the case where the relevant **HV Apparatus** of the **Implementing Safety Co-ordinator** is being either constructed or modified, an adequate physical separation as a result of a **No System Connection**.

(3) **“No System Connection”** means an adequate physical separation (which must be in accordance with, and maintained by, the method set out in the **Local Safety Instructions** of the **Implementing Safety Co-ordinator**) of the **Implementing Safety Co-ordinator’s** **HV Apparatus** from the rest of the **Implementing Safety Co-ordinator’s** **System** where such **HV Apparatus** has no installed means of being connected to, and will not for the duration of the **Safety Precaution** be connected to, a source of electrical energy or to any other part of the **Implementing Safety Co-ordinators System**.

(4) **"Earthing"** means a way of providing a connection between conductors and earth by an **Earthing Device** which is either:

(i) 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

(ii) maintained and/or secured in position by such other method which must be in accordance with the **Local Safety Instructions** of the **Relevant E&W Transmission Licensee** or that **E&W User** as the case may be.

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**OC8A.1.6.3** For the purpose of the co-ordination of safety relating to **HV Apparatus** the term **“Safety Precautions”** means **Isolation** and/or **Earthing**.

**OC8A.2** **OBJECTIVE**

**OC8A.2.1** The objective of OC8A is to achieve:-

(i) **Safety From The System** when work on or near a **System** necessitates the provision of **Safety Precautions** on another **System** on **HV Apparatus** up to a **Connection Point** (or, in the case of OTSUA, Transmission Interface Point); and
(ii) **Safety From The System** when work is to be carried out at an **E&W User’s Site** or a **Transmission Site** (as the case may be) on equipment of the **User** or the **Relevant E&W Transmission Licensee** (as the case may be) where the work or equipment is near to **HV Apparatus** on the **Implementing Safety Co-ordinator’s System**.

**OC8A.2.2**  
A flow chart, set out in **OC8A Appendix C**, illustrates the process utilised in **OC8A** to achieve the objective set out in **OC8A.2.1**. In the case of a conflict between the flow chart and the provisions of the written text of **OC8A**, the written text will prevail.

**OC8A.3**  
**SCOPE**

**OC8A.3.1**  
**OC8A** applies to the **Relevant E&W Transmission Licensee** and to **E&W Users**, which in **OC8A** means:

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

(b) **Network Operators**; and

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

The procedures for the establishment of safety co-ordination by **The Company** in relation to **External Interconnections** are set out in **Interconnection Agreements** with relevant persons for the **External Interconnections**.

**OC8A.4**  
**PROCEDURE**

**OC8A.4.1**  
**Approval of Local Safety Instructions**

**OC8A.4.1.1**  
(a) In accordance with the timing requirements of its **Bilateral Agreement**, each **E&W User** will supply to the **Relevant E&W Transmission Licensee** a copy of its **Local Safety Instructions** relating to its side of the **Connection Point** at each **Connection Site**, or in the case of **OTSUA** a copy of its **Local Safety Instructions** relating to its side of the **Transmission Interface Point** at each **Transmission Interface Site**.

(b) In accordance with the timing requirements of each **Bilateral Agreement**, the **Relevant E&W Transmission Licensee** will supply to each **E&W User** a copy of its **Local Safety Instructions** relating to the **Transmission** side of the **Connection Point** at each **Connection Site**, or in the case of **OTSUA** a copy of its **Local Safety Instructions** relating to the **Transmission** side of the **Transmission Interface Point** at each **Transmission Interface Site**.

(c) Prior to connection, the **Relevant E&W Transmission Licensee** and the **E&W User** must have approved each other's relevant **Local Safety Instructions** in relation to **Isolation** and **Earthing**.

**OC8A.4.1.2**  
Either party may require that the **Isolation** and/or **Earthing** provisions in the other party's **Local Safety Instructions** affecting the **Connection Site** (or, in the case of **OTSUA**, **Transmission Interface Site**) should be made more stringent in order that approval of the other party's **Local Safety Instructions** can be given. Provided these requirements are not unreasonable, the other party will make such changes as soon as reasonably practicable. These changes may need to cover the application of **Isolation** and/or **Earthing** at a place remote from the **Connection Site** (or, in the case of **OTSUA**, **Transmission Interface Site**), depending upon the **System** layout. Approval may not be withheld because the party required to approve reasonably believes the provisions relating to **Isolation** and/or **Earthing** are too stringent.

**OC8A.4.1.3**  
If, following approval, a party wishes to change the provisions in its **Local Safety Instructions** relating to **Isolation** and/or **Earthing**, it must inform the other party. If the change is to make the provisions more stringent, then the other party merely has to note the changes. If the change is to make the provisions less stringent, then the other party needs to approve the new provisions and the procedures referred to in **OC8A.4.1.2** apply.
OC8A.4.2 Safety Co-ordinators

OC8A.4.2.1 For each Connection Point, (or, in the case of OTSUA, Transmission Interface Point), the Relevant E&W Transmission Licensee and each E&W User will at all times have nominated an available a person or persons ("Safety Co-ordinator(s)") to be responsible for the co-ordination of Safety Precautions when work is to be carried out on a System which necessitates the provision of Safety Precautions on HV Apparatus pursuant to OC8A. A Safety Co-ordinator may be responsible for the co-ordination of safety on HV Apparatus at more than one Connection Point (or, in the case of OTSUA, Transmission Interface Point).

OC8A.4.2.2 Each Safety Co-ordinator shall be authorised by the Relevant E&W Transmission Licensee or an E&W User, as the case may be, as competent to carry out the functions set out in OC8A to achieve Safety From The System. Confirmation from the Relevant E&W Transmission Licensee or an E&W User, as the case may be, that its Safety Co-ordinator(s) as a group are so authorised is dealt with in CC.5.2 or in ECC.5.2. and for the Relevant E&W Transmission Licensees in the STC. Only persons with such authorisation will carry out the provisions of OC8A.

OC8A.4.2.3 Contact between Safety Co-ordinators will be made via normal operational channels, and accordingly separate telephone numbers for Safety Co-ordinators need not be provided. At the time of making contact, each party will confirm that they are authorised to act as a Safety Co-ordinator, pursuant to OC8A.

OC8A.4.2.4 If work is to be carried out on a System, or on equipment of the Relevant E&W Transmission Licensee or an E&W User near to a System, as provided in this OC8A, which necessitates the provision of Safety Precautions on HV Apparatus in accordance with the provisions of OC8A, the Requesting Safety Co-ordinator who requires the Safety Precautions to be provided shall contact the relevant Implementing Safety Co-ordinator to co-ordinate the establishment of the Safety Precautions.

OC8A.4.3 RISSP

OC8A.4.3.1 OC8A sets out the procedures for utilising the RISSP, which will be used except where dealing with equipment in proximity to the other’s System as provided in OC8A.8. Sections OC8A.4 to OC8A.7 inclusive should be read accordingly.

OC8A.4.3.2 The Relevant E&W Transmission Licensee will use the format of the RISSP forms set out in Appendix A and Appendix B to OC8A. That set out in OC8A Appendix A and designated as “RISSP-R”, shall be used when the Relevant E&W Transmission Licensee is the Requesting Safety Co-ordinator, and that in OC8A Appendix B and designated as "RISSP-I", shall be used when the Relevant E&W Transmission Licensee is the Implementing Safety Co-ordinator. Pro formas of RISSP-R and RISSP-I will be provided for use by the Relevant E&W Transmission Licensee staff.

OC8A.4.3.3 (a) E&W Users may either adopt the format referred to in OC8A.4.3.2, or use an equivalent format, provided that it includes sections requiring insertion of the same information and has the same numbering of sections as RISSP-R and RISSP-I as set out in Appendices A and B respectively.

(b) Whether E&W Users adopt the format referred to in OC8A.4.3.2, or use the equivalent format as above, the format may be produced and held in, and retrieved from an electronic form by the E&W User.

(c) Whichever method E&W Users choose, each must provide pro formas (whether in tangible or electronic form) for use by its staff.

OC8A.4.3.4 All references to RISSP-R and RISSP-I shall be taken as referring to the corresponding parts of the alternative forms or other tangible written or electronic records used by each E&W User.

OC8A.4.3.5 RISSP-R will have an identifying number written or printed on it, comprising a prefix which identifies the location at which it is issued, and a unique (for each E&W User or the Relevant E&W Transmission Licensee, as the case may be) serial number which both together uses up to eight characters (including letters and numbers) and the suffix "R". 
OC8A.4.3.6  (a) In accordance with the timing requirements set out in CC.5.2 or in ECC.5.2 each E&W User shall apply in writing to the Relevant E&W Transmission Licensee for the Relevant E&W Transmission Licensee’s approval of its proposed prefix.

(b) The Relevant E&W Transmission Licensee shall consider the proposed prefix to see if it is the same as (or confusingly similar to) a prefix used by the Relevant E&W Transmission Licensee or another User and shall, as soon as possible (and in any event within ten days), respond in writing to the E&W User with its approval or disapproval.

(c) If the Relevant E&W Transmission Licensee disapproves, it shall explain in its response why it has disapproved and will suggest an alternative prefix.

(d) If the Relevant E&W Transmission Licensee has disapproved, then the E&W User shall either notify the Relevant E&W Transmission Licensee in writing of its acceptance of the suggested alternative prefix or it shall apply in writing to the Relevant E&W Transmission Licensee with revised proposals and the above procedure shall apply to that application.

OC8A.4.3.7  The prefix allocation will be periodically circulated by NGET to all E&W Users, for information purposes, using a National Grid Safety Circular in the form set out in OC8A Appendix D.

OC8A.5  SAFETY PRECAUTIONS ON HV APPARATUS

OC8A.5.1  Agreement Of Safety Precautions

OC8A.5.1.1  The Requesting Safety Co-ordinator who requires Safety Precautions on another System(s) will contact the relevant Implementing Safety Co-ordinator(s) to agree the Location of the Safety Precautions to be established. This agreement will be recorded in the respective Safety Logs.

OC8A.5.1.2  It is the responsibility of the Implementing Safety Co-ordinator to ensure that adequate Safety Precautions are established and maintained, on their and/or another System connected to their System, to enable Safety From The System to be achieved on the HV Apparatus, specified by the Requesting Safety Co-ordinator which is to be identified in Part 1.1 of the RISSP. Reference to another System in this OC8A.5.1.2 shall not include the Requesting Safety Co-ordinator’s System which is dealt with in OC8A.5.1.3.

OC8A.5.1.3  When the Implementing Safety Co-ordinator is of the reasonable opinion that it is necessary for Safety Precautions on the System of the Requesting Safety Co-ordinator, other than on the HV Apparatus specified by the Requesting Safety Co-ordinator, which is to be identified in Part 1.1 of the RISSP, they shall contact the Requesting Safety Co-ordinator and the details shall be recorded in part 1.1 of the RISSP forms. In these circumstances it is the responsibility of the Requesting Safety Co-ordinator to establish and maintain such Safety Precautions.

OC8A.5.1.4  In The Event Of Disagreement

In any case where the Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator are unable to agree the Location of the Isolation and (if requested) Earthing, both shall be at the closest available points on the infeeds to the HV Apparatus on which Safety From The System is to be achieved as indicated on the Operation Diagram.

OC8A.5.2  Implementation Of Isolation

OC8A.5.2.1  Following the agreement of the Safety Precautions in accordance with OC8A.5.1 the Implementing Safety Co-ordinator shall then establish the agreed Isolation.
OC8A.5.2.2 The **Implementing Safety Co-ordinator** shall confirm to the **Requesting Safety Co-ordinator** that the agreed **Isolation** has been established, and identify the **Requesting Safety Co-ordinator’s HV Apparatus** up to the **Connection Point** (or, in the case of OTSUA, Transmission Interface Point), for which the **Isolation** has been provided. The confirmation shall specify:

(a) for each **Location**, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as applicable) of each point of **Isolation**;

(b) whether **Isolation** has been achieved by an **Isolating Device** in the isolating position, by an adequate physical separation or as a result of a **No System Connection**;

(c) where an **Isolating Device** has been used whether the isolating position is either:

   (i) maintained by immobilising and **Locking** the **Isolating Device** in the isolating position and affixing a **Caution Notice** to it. Where the **Isolating Device** has been **Locked** with a **Safety Key**, the confirmation shall specify that the **Safety Key** has been secured in a **Key Safe** and the **Key Safe Key** has been given to the authorised site representative of the **Requesting Safety Co-ordinator** where reasonably practicable and is to be retained in safe custody. Where not reasonably practicable (including where **Earthing** has been requested in OC8A.5.1), the confirmation shall specify that the **Key Safe Key** will 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** of the **Relevant E&W Transmission Licensee** or that E&W User, as the case may be; and

(d) where an adequate physical separation has been used that it will be in accordance with, and maintained by, the method set out in the **Local Safety Instructions** of the **Relevant E&W Transmission Licensee** or that E&W User, as the case may be, and, if it is a part of that method, that a **Caution Notice** has been placed at the point of separation;

(e) where a **No System Connection** has been used, the physical position of the **No System Connection** shall be defined and shall not be varied for the duration of **Safety Precaution** and the **Implementing Safety Co-ordinator’s** relevant **HV Apparatus** will not, for the duration of the **Safety Precaution** be connected to a source of electrical energy or to any other part of the **Implementing Safety Co-ordinator’s System**.

The confirmation of **Isolation** shall be recorded in the respective **Safety Logs**.

OC8A.5.2.3 Following the confirmation of **Isolation** being established by the **Implementing Safety Co-ordinator** and the necessary establishment of relevant **Isolation** on the **Requesting Safety Co-ordinators System**, the **Requesting Safety Co-ordinator** will then request the implementation of **Earthing** by the **Implementing Safety Co-ordinator**, if agreed in section OC8A.5.1. If the implementation of **Earthing** has been agreed, then the authorised site representative of the **Implementing Safety Co-ordinator** shall retain any **Key Safe Key** in safe custody until any **Safety Key** used for **Earthing** has been secured in the **Key Safe**.

OC8A.5.3 **Implementation Of Earthing**

OC8A.5.3.1 The **Implementing Safety Co-ordinator** shall then establish the agreed **Earthing**.

OC8A.5.3.2 The **Implementing Safety Co-ordinator** shall confirm to the **Requesting Safety Co-ordinator** that the agreed **Earthing** has been established, and identify the **Requesting Safety Co-ordinator’s HV Apparatus** up to the **Connection Point** (or, in the case of OTSUA, Transmission Interface Point), for which the **Earthing** has been provided. The confirmation shall specify:

(a) for each **Location**, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as is applicable) of each point of **Earthing**; and

(b) in respect of the **Earthing Device** used, whether it is:

   (i) immobilised and **Locked** in the earthing position. Where the **Earthing Device** has
been Locked with a Safety Key, that the Safety Key has been secured in a Key Safe and the Key Safe Key has been given to the authorised site representative of the Requesting Safety Co-ordinator where reasonably practicable and is to be retained in safe custody. Where not reasonably practicable, that the Key Safe Key will be retained by the authorised site representative of the Implementing Safety Co-ordinator in safe custody; or

(ii) maintained and/or secured in position by such other method which is in accordance with the Local Safety Instructions of the Relevant E&W Transmission Licensee or the Relevant Transmission Licensee or that E&W User, as the case may be.

The confirmation of Earthing shall be recorded in the respective Safety Logs.

OC8A.5.3.3. The Implementing Safety Co-ordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting Safety Co-ordinator.

OC8A.5.3.4 Certain designs of gas insulated switchgear three position isolator and earth switches specifically provide a combined Isolation and Earthing function within a single mechanism contained within a single integral unit. Where Safety Precautions are required across control boundaries and subject to the requirements of OC8A.5.1, it is permissible to earth before Points of Isolation have been established provided that all interconnected circuits are fully disconnected from live HV Apparatus.

OC8A.5.4 RISSP Issue Procedure

OC8A.5.4.1 Where Safety Precautions on another System(s) are being provided to enable work on the Requesting Safety Co-ordinator’s System, before any work commences they must be recorded by a RISSP being issued. The RISSP is applicable to HV Apparatus up to the Connection Point (or, in the case of OTSUA, Transmission Interface Point) identified in section 1.1 of the RISSP-R and RISSP-I forms.

OC8A.5.4.2 Where Safety Precautions are being provided to enable work to be carried out on both sides of the Connection Point (or, in the case of OTSUA, Transmission Interface Point) a RISSP will need to be issued for each side of the Connection Point (or, in the case of OTSUA, Transmission Interface Point) with the Relevant E&W Transmission Licensee and the respective User each enacting the role of Requesting Safety Co-ordinator. This will result in a RISSP-R and a RISSP-I form being completed by each of the Relevant E&W Transmission Licensee and the E&W User, with each Requesting Safety Co-ordinator issuing a separate RISSP number.

OC8A.5.4.3 Once the Safety Precautions have been established (in accordance with OC8A.5.2 and OC8A.5.3), the Implementing Safety Co-ordinator shall complete parts 1.1 and 1.2 of a RISSP-I form recording the details specified in OC8A.5.1.3, OC8A.5.2.2 and OC8A.5.3.2. Where Earthing has not been requested, Part 1.2(b) will be completed with the words “not applicable” or “N/A”. They shall then contact the Requesting Safety Co-ordinator to pass on these details.

OC8A.5.4.4 The Requesting Safety Co-ordinator shall complete Parts 1.1 and 1.2 of the RISSP-R, making a precise copy of the details received. On completion, the Requesting Safety Co-ordinator shall read the entries made back to the sender and check that an accurate copy has been made.

OC8A.5.4.5 The Requesting Safety Co-ordinator shall then issue the number of the RISSP, taken from the RISSP-R, to the Implementing Safety Co-ordinator who will ensure that the number, including the prefix and suffix, is accurately recorded in the designated space on the RISSP-I form.

OC8A.5.4.6 The Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator shall complete and sign Part 1.3 of the RISSP-R and RISSP-I respectively and then enter the time and date. When signed, no alteration to the RISSP is permitted; the RISSP may only be cancelled.
OC8A.5.4.7 The **Requesting Safety Co-ordinator** is then free to authorise work (including a test that does not affect the **Implementing Safety Co-ordinator’s System** in accordance with the requirements of the relevant internal safety procedures which apply to the **Requesting Safety Co-ordinator’s System**. This is likely to involve the issue of safety documents or other relevant internal authorisations. Where testing is to be carried out which affects the **Implementing Safety Co-ordinator’s System**, the procedure set out below in OC8A.6 shall be implemented.
OC8A.5.5  RISSP Cancellation Procedure

OC8A.5.5.1 When the Requesting Safety Co-ordinator decides that Safety Precautions are no longer required, they will contact the relevant Implementing Safety Co-ordinator to effect cancellation of the associated RISSP.

OC8A.5.5.2 The Requesting Safety Co-ordinator will inform the relevant Implementing Safety Co-ordinator of the RISSP identifying number (including the prefix and suffix), and agree it is the RISSP to be cancelled.

OC8A.5.5.3 The Requesting Safety Co-ordinator and the relevant Implementing Safety Co-ordinator shall then respectively complete Part 2.1 of their respective RISSP-R and RISSP-I forms and shall then exchange details. The details being exchanged shall include their respective names and time and date. On completion of the exchange of details, the respective RISSP is cancelled. The removal of Safety Precautions is as set out in OC8A.5.5.4 and OC8A.5.5.5.

OC8A.5.5.4 Neither Safety Co-ordinator shall instruct the removal of any Isolation forming part of the Safety Precautions as part of the returning of the HV Apparatus to service until it is confirmed to each by each other that every earth on each side of the Connection Point (or, in the case of OTSUA, Transmission Interface Point), within the points of isolation identified on the RISSP, has been removed or disconnected by the provision of additional Points of Isolation.

OC8A.5.5.5 Subject to the provisions in OC8A.5.5.4, the Implementing Safety Co-ordinator is then free to arrange the removal of the Safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Co-ordinator is representing. Where a Key Safe Key has been given to the authorised site representative of the Requesting Safety Co-ordinator, the Key Safe Key must be returned to the authorised site representative of the Implementing Safety Co-ordinator. The only situation in which any Safety Precautions may be removed without first cancelling the RISSP in accordance with OC8A.5.5 or OC8A.5.6 is when Earthing is removed in the situation envisaged in OC8A.6.2(b).

OC8A.5.6 RISSP Change Control

Nothing in this OC8A prevents the Relevant E&W Transmission Licensee and E&W Users agreeing to a simultaneous cancellation and issue of a new RISSP, if both agree. It should be noted, however, that the effect of that under the relevant Safety Rules is not a matter with which the Grid Code deals.

OC8A.6 TESTING AFFECTING ANOTHER SAFETY CO-ORDINATOR’S SYSTEM

OC8A.6.1 The carrying out of the test may affect Safety Precautions on RISSPs or work being carried out which does not require a RISSP. Testing can, for example, include the application of an independent test voltage. Accordingly, where the Requesting Safety Co-ordinator wishes to authorise the carrying out of such a test to which the procedures in OC8A.6 apply they may not do so and the test will not take place unless and until the steps in (a)-(c) below have been followed and confirmation of completion has been recorded in the respective Safety Logs:

(a) confirmation must be obtained from the Implementing Safety Co-ordinator that:

(i) no person is working on, or testing, or has been authorised to work on, or test, any part of its System or another System(s) (other than the System of the Requesting Safety Co-ordinator) within the points of Isolation identified on the RISSP form relating to the test which is proposed to be undertaken, and

(ii) no person will be so authorised until the proposed test has been completed (or cancelled) and the Requesting Safety Co-ordinator has notified the Implementing Safety Co-ordinator of its completion (or cancellation);

(b) any other current RISSPs which relate to the parts of the System in which the testing is to take place must have been cancelled in accordance with procedures set out in OC8A.5.5;
(c) The Implementing Safety Co-ordinator must agree with the Requesting Safety Co-ordinator to permit the testing on that part of the System between the points of Isolation identified in the RISSP associated with the test and the points of Isolation on the Requesting Safety Co-ordinator’s System.

OC8A.6.2

(a) The Requesting Safety Co-ordinator will inform the Implementing Safety Co-ordinator as soon as the test has been completed or cancelled and the confirmation shall be recorded in the respective Safety Logs.

(b) When the test gives rise to the removal of Earthing which it is not intended to re-apply, the relevant RISSP associated with the test shall be cancelled at the completion or cancellation of the test in accordance with the procedure set out in either OC8A.5.5 or OC8A.5.6. Where the Earthing is re-applied following the completion or cancellation of the test, there is no requirement to cancel the relevant RISSP associated with the test pursuant to this OC8A.6.2.

OC8A.7

EMERGENCY SITUATIONS

OC8A.7.1

There may be circumstances where Safety Precautions need to be established in relation to an unintended electrical connection or situations where there is an unintended risk of electrical connection between the National Electricity Transmission System and an E&W User’s System, for example resulting from an incident where one line becomes attached or unacceptably close to another.

OC8A.7.2

In those circumstances, if both the Relevant E&W Transmission Licensee and the respective E&W User agree, the relevant provisions of OC8A.5 will apply as if the electrical connections or potential connections were, solely for the purposes of this OC8A, a Connection Point (or, in the case of OTSUA, Transmission Interface Point).

OC8A.7.3

(a) The relevant Safety Co-ordinator shall be that for the electrically closest existing Connection Point (or, in the case of OTSUA, Transmission Interface Point) to that E&W User’s System or such other local Connection Point (or, in the case of OTSUA, Transmission Interface Point) as may be agreed between the Relevant E&W Transmission Licensee and the E&W User, with discussions taking place between the relevant local Safety Co-ordinators. The Connection Point (or, in the case of OTSUA, Transmission Interface Point) to be used shall be known in this OC8A.7.3 as the “relevant Connection Point” (or, in the case of OTSUA, “relevant Transmission Interface Point”).

(b) The Local Safety Instructions shall be those which apply to the relevant Connection Point (or, in the case of OTSUA, Transmission Interface Point).

(c) The prefix for the RISSP will be that which applies for the relevant Connection Point (or, in the case of OTSUA, Transmission Interface Point).
SAFETY PRECAUTIONS RELATING TO WORKING ON EQUIPMENT NEAR TO THE HV SYSTEM

OC8A.8 applies to the situation where work is to be carried out at an E&W User’s Site or a Transmission Site (as the case may be) on equipment of the User or the Relevant E&W Transmission Licensee as the case may be, where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System. It does not apply to other situations to which OC8A applies. In this part of OC8A, a Permit for Work for proximity work is to be used, rather than the usual RISSP procedure, given the nature and effect of the work, all as further provided in the OC8A.8.

OC8A.8.1 Agreement Of Safety Precautions

OC8A.8.1.1 The Requesting Safety Co-ordinator who requires Safety Precautions on another System(s) when work is to be carried out at an E&W User’s Site or a Transmission Site (as the case may be) on equipment of the User or the Relevant E&W Transmission Licensee, as the case may be, where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System will contact the relevant Implementing Safety Co-ordinator(s) to agree the location of the Safety Precautions to be established, having as part of this process informed the Implementing Safety Co-ordinator of the equipment and the work to be undertaken. The respective Safety Co-ordinators will ensure that they discuss the request with their authorised site representative and that the respective authorised site representatives discuss the request at the Connection Site (or, in the case of OTSUA, Transmission Interface Site). This agreement will be recorded in the respective Safety Logs.

OC8A.8.1.2 It is the responsibility of the Implementing Safety Co-ordinator, working with their authorised site representative as appropriate, to ensure that adequate Safety Precautions are established and maintained, on their and/or another System connected to their System, to enable Safety From The System to be achieved for work to be carried out at an E&W User’s Site or a Transmission Site (as the case may be) on equipment and in relation to work which is to be identified in the relevant part of the Permit for Work for proximity work where the work or equipment is near to HV Apparatus of the Implementing Safety Co-ordinator’s System specified by the Requesting Safety Co-ordinator. Reference to another System in this OC8A.8.1.2 shall not include the Requesting Safety Co-ordinator’s System.

OC8A.8.1.3 In The Event Of Disagreement

In any case, where the Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator are unable to agree the Location of the Isolation and (if requested) Earthing, both shall be at the closest available points on the infeeds to the HV Apparatus near to which the work is to be carried out as indicated on the Operation Diagram.

OC8A.8.2 Implementation Of Isolation And Earthing

OC8A.8.2.1 Following the agreement of the Safety Precautions in accordance with OC8A.8.1 the Implementing Safety Co-ordinator shall then establish the agreed Isolation and (if required) Earthing.

OC8A.8.2.2 The Implementing Safety Co-ordinator shall confirm to the Requesting Safety Co-ordinator that the agreed Isolation and (if required) Earthing has been established.

OC8A.8.2.3 The Implementing Safety Co-ordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting Safety Co-ordinator.
OC8A.8.3 Permit For Work For Proximity Work Issue Procedure

OC8A.8.3.1 Where Safety Precautions on another System(s) are being provided to enable work to be carried out at an E&W User’s Site or Transmission Site (as the case may be) on equipment where the work or equipment is in proximity to HV Apparatus of the Implementing Safety Co-ordinator, before any work commences they must be recorded by a Permit for Work for proximity work being issued. The Permit for Work for proximity work shall identify the Implementing Safety Co-ordinator’s HV Apparatus in proximity to the required work.

OC8A.8.3.2 Once the Safety Precautions have been established (in accordance with OC8A.8.2), the Implementing Safety Co-ordinator shall agree to the issue of the Permit for Work for proximity work with the appropriately authorised site representative of the Requesting Safety Co-ordinator’s Site. The Implementing Safety Co-ordinator will inform the Requesting Safety Co-ordinator of the Permit for Work for proximity work identifying number.

OC8A.8.3.3 The appropriately authorised site representative of the Implementing Safety Co-ordinator shall then issue the Permit for Work for proximity work to the appropriately authorised site representative of the Requesting Safety Co-ordinator. The Permit for Work for proximity work will in the section dealing with the work to be carried out, be completed to identify that the work is near the Implementing Safety Co-ordinator’s HV Apparatus. No further details of the Requesting Safety Co-ordinator’s work will be recorded, as that is a matter for the Requesting Safety Co-ordinator in relation to their work.

OC8A.8.3.4 The Requesting Safety Co-ordinator is then free to authorise work in accordance with the requirements of the relevant internal safety procedures which apply to the Requesting Safety Co-ordinator’s Site. This is likely to involve the issue of safety documents or other relevant internal authorisations.

OC8A.8.4 Permit For Work For Proximity Work Cancellation Procedure

OC8A.8.4.1 When the Requesting Safety Co-ordinator decides that Safety Precautions are no longer required, they will contact the relevant Implementing Safety Co-ordinator to effect cancellation of the associated Permit for Work for proximity work.

OC8A.8.4.2 The Requesting Safety Co-ordinator will inform the relevant Implementing Safety Co-ordinator of the Permit for Work for proximity work identifying number, and agree that the Permit for Work for proximity work can be cancelled. The cancellation is then effected by the appropriately authorised site representative of the Requesting Safety Co-ordinator returning the Permit for Work for proximity work to the appropriately authorised site representative of the Implementing Safety Co-ordinator.

OC8A.8.4.3 The Implementing Safety Co-ordinator is then free to arrange the removal of the Safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Co-ordinator is representing.

OC8A.9 LOSS OF INTEGRITY OF SAFETY PRECAUTIONS

OC8A.9.1 In any instance when any Safety Precautions may be ineffective for any reason the relevant Safety Co-ordinator shall inform the other Safety Co-ordinator(s) without delay of that being the case and, if requested, of the reasons why.

OC8A.10 SAFETY LOG

OC8A.10.1 The Relevant E&W Transmission Licensee and E&W Users shall maintain Safety Logs which shall be a chronological record of all messages relating to safety co-ordination under OC8A sent and received by the Safety Co-ordinator(s). The Safety Logs must be retained for a period of not less than one year.
APPENDIX A - RISSP-R

[the Relevant E&W Transmission Licensee] [control centre/site]

RECORD OF INTER-SYSTEM SAFETY PRECAUTIONS (RISSP-R)
(Requesting Safety Co-ordinator’s Record)

RISSP NUMBER

PART 1

1.1 HV APPARATUS IDENTIFICATION

Safety Precautions have been established by the Implementing Safety Co-ordinator (or by another User on that User’s System connected to the Implementing Safety Co-ordinator’s System) to achieve (in so far as is possible from that side of the Connection Point/Transmission Interface Point) Safety From The System on the following HV Apparatus on the Requesting Safety Co-ordinator’s System: [State identity - name(s) and, where applicable, identification of the HV circuit(s) up to the Connection Point/Transmission Interface Point]:

______________________________________________________________________________________________

______________________________________________________________________________________________

Further Safety precautions required on the Requesting Safety Co-ordinator’s System as notified by the Implementing Safety Co-ordinator.

______________________________________________________________________________________________

1.2 SAFETY PRECAUTIONS ESTABLISHED

(a) ISOLATION

[State the Location(s) at which Isolation has been established (whether on the Implementing Safety Co-ordinator’s System or on the System of another User connected to the Implementing Safety Co-ordinator’s System). For each Location, identify each point of Isolation. For each point of Isolation, state the means by which the Isolation has been achieved, and whether, immobilised and Locked, Caution Notice affixed, other safety procedures applied, as appropriate.]

______________________________________________________________________________________________

______________________________________________________________________________________________

______________________________________________________________________________________________

(b) EARTHING

[State the Location(s) at which Earthing has been established (whether on the Implementing Safety Co-ordinator’s System or on the System of another User connected to the Implementing Safety Co-ordinator’s System). For each Location, identify each point of Earthing. For each point of Earthing, state the means by which Earthing has been achieved, and whether, immobilised and Locked, other safety procedures applied, as appropriate].

______________________________________________________________________________________________

______________________________________________________________________________________________

______________________________________________________________________________________________

1.3 ISSUE

I have received confirmation from _________________________________________ (name of Implementing Safety Co-ordinator) at _________________________________________ (location) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at their location for their removal until this RISSP is cancelled.

Signed ...................................................(Requesting Safety Co-ordinator)

at ..............................................(time) on .................................................. (Date)
PART 2

2.1 CANCELLATION

I have confirmed to _____________________________ (name of the Implementing Safety Co-ordinator) at _____________________________ (location) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly the RISSL is cancelled.

Signed ________________________________ (Requesting Safety Co-ordinator)

at _________________________ (time) on ________________________________ (Date)
APPENDIX B - RISSP-I

[the Relevant E&W Transmission Licensee]  [_________________ CONTROL CENTRE/SITE]

RECORD OF INTER-SYSTEM SAFETY PRECAUTIONS (RISSP-I)
(Implementing Safety Co-ordinator’s Record)

PART 1

1.1 HV APPARATUS IDENTIFICATION

Safety Precautions have been established by the Implementing Safety Co-ordinator (or by another User on that User’s System connected to the Implementing Safety Co-ordinator’s System) to achieve (in so far as it is possible from that side of the Connection Point/Transmission Interface Point) Safety From The System on the following HV Apparatus on the Requesting Safety Co-ordinator’s System: [State identity - name(s) and, where applicable, identification of the HV circuit(s) up to the Connection Point/Transmission Interface Point]:

______________________________________________________________________________________________
______________________________________________________________________________________________

Recording of notification given to the Requesting Safety Co-ordinator concerning further Safety Precautions required on the Requesting Safety Co-ordinator’s System.

1.2 SAFETY PRECAUTIONS ESTABLISHED

(a) ISOLATION

[State the Location(s) at which Isolation has been established (whether on the Implementing Safety Co-ordinator’s System or on the System of another User connected to the Implementing Safety Co-ordinator’s System). For each Location, identify each point of Isolation. For each point of Isolation, state the means by which the Isolation has been achieved, and whether, immobilised and Locked, Caution Notice affixed, other safety procedures applied, as appropriate.]

______________________________________________________________________________________________

(b) EARTHING

[State the Location(s) at which Earthing has been established (whether on the Implementing Safety Co-ordinator’s System or on the System of another User connected to the Implementing Safety Co-ordinator’s System). For each Location, identify each point of Earthing. For each point of Earthing, state the means by which Earthing has been achieved, and whether, immobilised and Locked, other safety procedures applied, as appropriate].

______________________________________________________________________________________________

1.3 ISSUE

I have confirmed to ______________________________________ (name of Requesting Safety Co-ordinator) at __________________________________ (location) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at my location for their removal until this RISSP is cancelled.

Signed ............................................................... (Implementing Safety Co-ordinator)
at ............................................................... (time) on ............................................................... (Date)
PART 2

2.1 CANCELLATION

I have received confirmation from ___________________________ (name of the Requesting Safety Co-ordinator) at __________________________ (location) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly the RISSP is cancelled.

Signed .................................................. (Implementing Safety Co-ordinator)

at ...................................................(time) on .................................................. (Date)

(Note: This form to be of a different colour from RISSP-R)
APPENDIX C2 - TESTING PROCESS

Where testing affects another Safety Co-ordinator’s System

- Continue from OC8A Appendix C1

Testing will not take place by RSC until:

- OC8A.5.1

ISC confirms that no person is working or testing or authorised to, on his System or another System within the points of Isolation on the RISSP

- Log
  - OC8A.6.1(a)(1)

No person will be so authorised until proposed test is completed (or cancelled) by the RSC

- OC8A.6.1(a)(ii)

Arr RISSP other than for the proposed test shall be cancelled

- OC8A.5.1(b)

The ISC agrees to the testing between the points of Isolation on the RISSP and the RSC System

- OC8A.5.1(c)

Test can now take place

When test is complete or cancelled, RSC informs ISC

- Log
  - OC8A.6.2(a)

If testing required the removal of earthing the RISSP process is as set out in:

- OC8A.6.2(b)

Earthing reapplied

- OC8A.6.2(b)

Earthing not reapplied

- OC8A.6.2(b)

RISSP cancellation process. See OC8A Appendix C3
APPENDIX C3 - RISSP CANCELLATION PROCESS

Requesting Safety Co-ordinator (RSC)
Person requiring Safety Precaution from another User

Implementing Safety Co-ordinator (ISC)
Person who co-ordinates provision of Safety Precautions

Work/Testing completed or cancelled

RSC contacts ISC to inform safety precautions are no longer required

RSC informs ISC of RISSP document to be cancelled (including identity numbers)

The RSC and ISC complete their respective parts of section 2.1 on RISSP-R and RISSP-I

The RSC and ISC exchange the details including respective names, times and date

RISSP is now cancelled

Agree removal of Safety Precautions

Agreed between RSC and ISC that all earths are removed

Removal of earthing during testing across the Connection Point/Transmission Interface Point is as set out in OC8A.6.2(b)

Removal of isolation agreed between RSC and ISC

OC8A process complete

Removal being an internal matter for the party the ISC represents

OC8A.5.5.5
Pursuant to the objectives of The Grid Code, Operating Code 8A1 - Safety Co-ordination, this circular will be used in relation to all cross boundary safety management issues with the Relevant E&W Transmission Licensee customers. Of particular note will be the agreed prefixes for the Record of Inter System Safety Precautions (RISSP) documents.
APPENDIX E - FORM OF NGET’S PERMIT TO WORK

[Form of the Relevant E&W Transmission Licensee Permit for Work]

PERMIT FOR WORK

1. Location…………………………………………………………………………………………………………………………………………
   Equipment Identification…………………………………………………………………………………………………………………..
   Work to be done……………………………………………………………………………………………………………………………

2. Precautions taken to achieve Safety from the System
   Points of Isolation
   Primary Earths
   Actions taken to avoid Danger by draining, venting, purging and containment or dissipation of stored energy*
   Further precautions to be taken during the course of the work to avoid System derived hazards*

3. Precautions that may be varied*

4. Preparation Control Person(s) (Safety) giving Consent………………………………………………………………………..
   State whether this Permit for Work must be personally retained yes no
   Signed………………………………………………………………………………………………………………………………………..
   Key Safe number*
   Time………………………………………………………………………………………………………………………………………..
   Date…………………………………………………………………………………………………………………………………………
   Senior Authorised Person

No.
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<td>Approved (ROMP)#/Card Safe#/Procedure Number*</td>
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**Senior Authorised Person**

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February 1995

< END OF OPERATING CODE NO. 8 APPENDIX 1>
# OPERATING CODE NO. 8 APPENDIX 2

(OC8B)

## SAFETY CO-ORDINATION IN RESPECT OF THE SCOTTISH TRANSMISSION SYSTEMS OR THE SYSTEMS OF SCOTTISH USERS

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OC8B.1 INTRODUCTION

OC8B.1.1 OC8B specifies the standard procedures to be used by The Company, the Relevant Scottish Transmission Licensees and Scottish Users for the co-ordination, establishment and maintenance of necessary Safety Precautions when work is to be carried out on or near the Scottish Transmission System or the System of a Scottish User and when there is a need for Safety Precautions on HV Apparatus on the other’s System for this work to be carried out safely. OC8B applies to Relevant Scottish Transmission Licensees and Scottish Users. Where work is to be carried out on or near equipment on an E&W Transmission System or the Systems of E&W Users, but such work requires Safety Precautions to be established on a Scottish Transmission System or the Systems of Scottish Users. OC8B should be followed by the Relevant Scottish Transmission Licensee and Scottish Users to establish the required Safety Precautions.

OC8A specifies the procedures to be used by the Relevant E&W Transmission Licensee and E&W Users.

The Company shall procure that Relevant Scottish Transmission Licensees shall comply with OC8B where and to the extent that such section applies to them. In this OC8B, the term “work” includes testing, other than System Tests which are covered by OC12.

OC8B.1.2 OC8B also covers the co-ordination, establishment and maintenance of necessary safety precautions on the Implementing Safety Co-ordinator’s System when work is to be carried out at a Scottish User’s Site or a Transmission Site (as the case may be) on equipment of the Scottish User or the Relevant Scottish Transmission Licensee as the case may be where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System. In the case of OTSUA, a Scottish User’s Site or Transmission Site shall, for the purposes of this OC8B, include a site at which there is a Transmission Interface Point until the OTSUA Transfer Time and the provisions of this OC8B and references to OTSUA shall be construed and applied accordingly until the OTSUA Transfer Time at which time arrangements in respect of the Transmission Interface Site will have been put in place between the Relevant Scottish Transmission Licensee and the Offshore Transmission Licensee.

OC8B.1.3 OC8B does not apply to the situation where Safety Precautions need to be agreed solely between Scottish Users. OC8B does not apply to the situation where Safety Precautions need to be agreed solely between Transmission Licensees.

OC8B.1.4 OC8B does not seek to impose a particular set of Safety Rules on Relevant Scottish Transmission Licensees and Scottish Users. The Safety Rules to be adopted and used by the Relevant Scottish Transmission Licensee and each Scottish User shall be those chosen by each.

OC8B.1.5 Site Responsibility Schedules document the control responsibility for each item of Plant and Apparatus for each site.

OC8B.1.6 (a) The Relevant Scottish Transmission Licensee may agree alternative site-specific operational procedures with Scottish Users for the co-ordination, establishment and maintenance of Safety Precautions instead of the Record of Inter-System Safety Precautions (“RISSP”) procedure detailed in this OC8B. Such operational procedures shall satisfy the requirements of paragraphs OC8B.1.7, OC8B.2.1, OC8B.4.1, OC8B.4.2, OC8B.9, OC8B.10. These alternative site-specific operational procedures for the co-ordination, establishment, and maintenance of Safety Precautions will be referenced in the relevant Site Responsibility Schedule.
(b) The Relevant Scottish Transmission Licensee may agree with Scottish Users site-specific procedures for the application of Safety Precautions across the interface between the Relevant Scottish Transmission Licensee and Scottish User in addition to and consistent with either the RISSP procedure or the alternative site-specific operational procedures described in OC8B.1.6 (a). These site-specific procedures will be referenced in the relevant Site Responsibility Schedule.

(c) The Relevant Scottish Transmission Licensee and the Scottish User shall comply with the procedures agreed pursuant to OC8B.1.6 (a) and OC8B.1.6 (b).

OC8B.1.7 Defined Terms

OC8B.1.7.1 Scottish Users should bear in mind that in OC8 only, in order that OC8 reads more easily with the terminology used in certain Safety Rules, the term "HV Apparatus" is defined more restrictively and is used accordingly in OC8B. Scottish Users should, therefore, exercise caution in relation to this term when reading and using OC8B.

OC8B.1.7.2 In OC8 only the following terms shall have the following meanings:

(1) "HV Apparatus" means High Voltage electrical circuits forming part of a System, on which Safety From The System may be required or on which Safety Precautions may be applied to allow work to be carried out on a System.

(2) "Isolation" means the disconnection of Apparatus from the remainder of the System in which that 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 given to the authorised site representative of the Requesting Safety Co-ordinator where reasonably practicable 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 Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish 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 Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish User, as the case may be, and, if it is a part of that method, a Caution Notice must be placed at the point of separation; or

(c) in the case where the relevant HV Apparatus of the Implementing Safety Co-ordinator is being either constructed or modified, an adequate physical separation as a result of a No System Connection.

(3) “No System Connection” means an adequate physical separation (which must be in accordance with, and maintained by, the method set out in the Safety Rules of the Implementing Safety Co-ordinator) of the Implementing Safety Co-ordinator’s HV Apparatus from the rest of the Implementing Safety Co-ordinator’s System where such HV Apparatus has no installed means of being connected to, and will not for the duration of the Safety Precaution be connected to, a source of electrical energy or to any other part of the Implementing Safety Co-ordinator’s System.

(4) "Earthing" means a way of providing a connection between conductors and earth by an Earthing Device which is either:

(i) 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 given to the authorised site representative of the Requesting Safety Co-ordinator where reasonably practicable 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 in position by such other method which must be in accordance with the Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish User as the case may be.

OC8B.1.7.3 For the purpose of the co-ordination of safety relating to HV Apparatus the term “Safety Precautions” means Isolation and/or Earthing.

OC8B.2 OBJECTIVE

OC8B.2.1 The objective of OC8B is to achieve:-

(i) Safety From The System when work on or near a System necessitates the provision of Safety Precautions on another System on HV Apparatus up to a Connection Point (or, in the case of OTSUA, Transmission Interface Point); and

(ii) Safety From The System when work is to be carried out at a Scottish User’s Site or a Transmission Site (as the case may be) on equipment of the Scottish User or the Relevant Scottish Transmission Licensee (as the case may be) where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System.
OC8B.2.2 A flow chart, set out in OC8B Appendix C, illustrates the process utilised in OC8B to achieve the objective set out in OC8B.2.1. In the case of a conflict between the flow chart and the provisions of the written text of OC8B, the written text will prevail.

OC8B.3 SCOPE
OC8B.3.1 OC8B applies to The Company, Relevant Scottish Transmission Licensees and to Scottish Users, which in OC8 means:-
(a) Generators (including where undertaking OTSDUW);
(b) Network Operators; and
(c) Non-Embedded Customers.
The procedures for the establishment of safety co-ordination by The Company in relation to External Interconnections are set out in Interconnection Agreements with relevant persons for the External Interconnections.

OC8B.4 PROCEDURE
OC8B.4.1 Approval Of Safety Rules
OC8B.4.1.1 (a) In accordance with the timing requirements of its Bilateral Agreement, each Scottish User will supply to the Relevant Scottish Transmission Licensee a copy of its Safety Rules relating to its side of the Connection Point at each Connection Site or in the case of OTSUA a copy of its Local Safety Instructions relating to its side of the Transmission Interface Point at each Transmission Interface Site.
(b) In accordance with the timing requirements of each Bilateral Agreement, the Relevant Scottish Transmission Licensee will supply to each Scottish User a copy of its Safety Rules relating to the Transmission side of the Connection Point at each Connection Site or in the case of OTSUA a copy of its Local Safety Instructions relating to the Transmission side of the Transmission Interface Point at each Transmission Interface Site.
(c) Prior to connection the Relevant Scottish Transmission Licensee and the Scottish User must have approved each other’s relevant Safety Rules in relation to Isolation and Earthing.

OC8B.4.1.2 Either party may require that the Isolation and/or Earthing provisions in the other party’s Safety Rules affecting the Connection Site (or, in the case of OTSUA, Transmission Interface Site) should be made more stringent in order that approval of the other party’s Safety Rules can be given. Provided these requirements are not unreasonable, the other party will make such changes as soon as reasonably practicable. These changes may need to cover the application of Isolation and/or Earthing at a place remote from the Connection Site (or, in the case of OTSUA, Transmission Interface Site), depending upon the System layout. Approval may not be withheld because the party required to approve reasonably believes the provisions relating to Isolation and/or Earthing are too stringent.

OC8B.4.1.3 If, following approval, a party wishes to change the provisions in its Safety Rules relating to Isolation and/or Earthing, it must inform the other party. If the change is to make the provisions more stringent, then the other party merely has to note the changes. If the change is to make the provisions less stringent, then the other party needs to approve the new provisions and the procedures referred to in OC8B.4.1.2 apply.

OC8B.4.2 Safety Co-ordinators
For each Connection Point (or, in the case of OTSUA, Transmission Interface Point), the Relevant Scottish Transmission Licensee and each Scottish User will have nominated to be available, to a timescale agreed in the Bilateral Agreement, a person or persons (“Safety Co-ordinator(s)”) to be responsible for the co-ordination of Safety Precautions when work is to be carried out on a System which necessitates the provision of Safety Precautions on HV Apparatus pursuant to OC8B. A Safety Co-ordinator may be responsible for the co-ordination of safety on HV Apparatus at more than one Connection Point (or, in the case of OTSUA, Transmission Interface Point).

Each Safety Co-ordinator shall be authorised by the Relevant Scottish Transmission Licensee or a Scottish User, as the case may be, as competent to carry out the functions set out in OC8B to achieve Safety From The System. Confirmation from the Relevant Transmission Licensee or a Scottish User, as the case may be, that its Safety Co-ordinator(s) as a group are so authorised is dealt with, for Scottish Users, in CC.5.2 or in ECC.5.2 and for Relevant Scottish Transmission Licensees in the STC. Only persons with such authorisation will carry out the provisions of OC8B. Each User shall, prior to being connected to the National Electricity Transmission System, give notice in writing to the Relevant Scottish Transmission Licensee of its Safety Co-ordinator(s) and will update the written notice yearly and whenever there is a change to the identity of its Safety Co-ordinators or to the Connection Points (or, in the case of OTSUA, Transmission Interface Points). The Relevant Scottish Transmission Licensee will, at the time of a Scottish User being connected to the National Electricity Transmission System give notice in writing to that Scottish User of the identity of its Safety Co-ordinator(s) and will update the written notice whenever there is a change to the Connection Points (or, in the case of OTSUA, Transmission Interface Points) or Safety Co-ordinators.

Contact between Safety Co-ordinators will be made via normal operational channels, and accordingly separate telephone numbers for Safety Co-ordinators need not be provided.

If work is to be carried out on a System, or on equipment of the Relevant Scottish Transmission Licensee or a Scottish User near to a System, as provided in this OC8B, which necessitates the provision of Safety Precautions on HV Apparatus in accordance with the provisions of OC8B, the Requesting Safety Co-ordinator who requires the Safety Precautions to be provided shall contact the relevant Implementing Safety Co-ordinator to co-ordinate the establishment of the Safety Precautions.

The Relevant Transmission Licensee will use the format of the RISSP forms set out in Appendix A and Appendix B to OC8B, or any other format which may be agreed between the Relevant Scottish Transmission Licensee and each User. That set out in OC8B Appendix A and designated as "RISSP-R", shall be used when the Relevant Scottish Transmission Licensee is the Requesting Safety Co-ordinator, and that in OC8B Appendix B and designated as "RISSP-I", shall be used when the Relevant Transmission Licensee is the Implementing Safety Co-ordinator. Proforms of RISSP-R and RISSP-I will be provided for use by Relevant Scottish Transmission Licensees staff.

Scottish Users may either adopt the format referred to in OC8B.4.3.2 or any other format which may be agreed between the Relevant Scottish Transmission Licensee and the Scottish User from time to time.

All references to RISSP-R and RISSP-I shall be taken as referring to the corresponding parts of the alternative forms or other tangible written or electronic records used by each Scottish User or Relevant Scottish Transmission Licensee.

RISSP-R will have an identifying number written or printed on it, comprising a prefix which identifies the location at which it is issued, and a unique (for each Scottish User or Relevant Scottish Transmission Licensee, as the case may be) serial number which both together uses up to eight characters (including letters and numbers) and the suffix "R".
OC8B.4.3.6 (a) In accordance with the timing requirements set out in the Bilateral Agreement each Scottish User shall apply in writing to the Relevant Scottish Transmission Licensee for the Relevant Scottish Transmission Licensee’s approval of its proposed prefix.

(b) The Relevant Scottish Transmission Licensee shall consider the proposed prefix to see if it is the same as (or confusingly similar to) a prefix used by the Relevant Scottish Transmission Licensee or another User and shall, as soon as possible (and in any event within ten days), respond in writing to the Scottish User with its approval or disapproval.

(c) If the Relevant Scottish Transmission Licensee disapproves, it shall explain in its response why it has disapproved and will suggest an alternative prefix.

(d) If the Relevant Scottish Transmission Licensee has disapproved, then the Scottish User shall either notify the Relevant Scottish Transmission Licensee in writing of its disapproval or another User and the details shall be recorded in Part 1.1 of the RISSP.

OC8B.5 SAFETY PRECAUTIONS ON HV APPARATUS

OC8B.5.1 Agreement Of Safety Precautions

OC8B.5.1.1 The Requesting Safety Co-ordinator who requires Safety Precautions on another System(s) will contact the relevant Implementing Safety Co-ordinator(s) to agree the Location of the Safety Precautions to be established. This agreement will be recorded in the respective Safety Logs.

OC8B.5.1.2 It is the responsibility of the Implementing Safety Co-ordinator to ensure that adequate Safety Precautions are established and maintained, on their and/or another System connected to their System, to enable Safety From The System to be achieved on the HV Apparatus, specified by the Requesting Safety Co-ordinator which is to be identified in Part 1.1 of the RISSP. Reference to another System in this OC8B.5.1.2 shall not include the Requesting Safety Co-ordinator’s System which is dealt with in OC8B.5.1.3.

OC8B.5.1.3 When the Implementing Safety Co-ordinator is of the reasonable opinion that it is necessary for Safety Precautions on the System of the Requesting Safety Co-ordinator, other than on the HV Apparatus specified by the Requesting Safety Co-ordinator, which is to be identified in Part 1.1 of the RISSP, they shall contact the Requesting Safety Co-ordinator and the details shall be recorded in part 1.1 of the RISSP forms. In these circumstances it is the responsibility of the Requesting Safety Co-ordinator to establish and maintain such Safety Precautions.

OC8B.5.1.4 The location of the Safety Precautions should be indicated on each Scottish User’s operational diagram and labelled as per the local instructions of each Scottish User.

OC8B.5.1.5 In The Event Of Disagreement

In any case where the Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator are unable to agree the Location of the Isolation and (if requested) Earthing, both shall be at the closest available points on the infeeds to the HV Apparatus on which Safety From The System is to be achieved as indicated on the Operation Diagram.

OC8B.5.2 Implementation Of Isolation

OC8B.5.2.1 Following the agreement of the Safety Precautions in accordance with OC8B.5.1 the Implementing Safety Co-ordinator shall then establish the agreed Isolation.

OC8B.5.2.2 The Implementing Safety Co-ordinator shall confirm to the Requesting Safety Co-ordinator that the agreed Isolation has been established, and identify the Requesting Safety Co-ordinator’s HV Apparatus up to the Connection Point (or, in the case of OTSUA, Transmission Interface Point), for which the Isolation has been provided. The confirmation shall specify:
(a) for each Location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as applicable) of each point of Isolation;
(b) whether Isolation has been achieved by an Isolating Device in the isolating position, by an adequate physical separation or as a result of a No System Connection;
(c) where an Isolating Device has been used whether the isolating position is either:
   (i) maintained by immobilising and Locking the Isolating Device in the isolating position and affixing a Caution Notice to it. Where the Isolating Device has been Locked with a Safety Key, the confirmation shall specify that the Safety Key has been secured in a Key Safe and the Key Safe Key has been given to the authorised site representative of the Requesting Safety Co-ordinator where reasonably practicable and is to be retained in safe custody. Where not reasonably practicable (including where Earthing has been requested in OC8B.5.1), the confirmation shall specify that the Key Safe Key will 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 Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish User, as the case may be; and
(d) where an adequate physical separation has been used that it will be in accordance with, and maintained by, the method set out in the Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish User, as the case may be, and, if it is a part of that method, that a Caution Notice has been placed at the point of separation;
(e) where a No System Connection has been used, the physical position of the No System Connection shall be defined and shall not be varied for the duration of the Safety Precaution and the Implementing Safety Co-ordinator’s relevant HV Apparatus will not, for the duration of the Safety Precaution be connected to a source of electrical energy or to any other part of the Implementing Safety Co-ordinator’s System.

The confirmation of Isolation shall be recorded in the respective Safety Logs.

OC8B.5.2.3 Following the confirmation of Isolation being established by the Implementing Safety Co-ordinator and the necessary establishment of relevant Isolation on the Requesting Safety Co-ordinators System, the Requesting Safety Co-ordinator will then request the implementation of Earthing by the Implementing Safety Co-ordinator, if agreed in section OC8B.5.1. If the implementation of Earthing has been agreed, then the authorised site representative of the Implementing Safety Co-ordinator shall retain any Key Safe Key in safe custody until any Safety Key used for Earthing has been secured in the Key Safe.

OC8B.5.3 Implementation Of Earthing

OC8B.5.3.1 The Implementing Safety Co-ordinator shall then establish the agreed Earthing.

OC8B.5.3.2 The Implementing Safety Co-ordinator shall confirm to the Requesting Safety Co-ordinator that the agreed Earthing has been established, and identify the Requesting Safety Co-ordinator’s HV Apparatus up to the Connection Point (or, in the case of OTSUA, Transmission Interface Point), for which the Earthing has been provided. The confirmation shall specify:

(a) for each Location, the identity (by means of HV Apparatus name, nomenclature and numbering or position, as is applicable) of each point of Earthing; and

(b) in respect of the Earthing Device used, whether it is:

   (i) immobilised and Locked in the earthing position. Where the Earthing Device has been Locked with a Safety Key, that the Safety Key has been secured in a Key Safe and the Key Safe Key has been given to the authorised site representative of the Requesting Safety Co-ordinator where reasonably practicable and is to be retained in safe custody. Where not reasonably practicable, that the Key Safe Key
will be retained by the authorised site representative of the Implementing Safety Co-ordinator in safe custody; or

(ii) maintained and/or secured in position by such other method which is in accordance with the Safety Rules of the Relevant Scottish Transmission Licensee or that Scottish User, as the case may be.

The confirmation of Earthing shall be recorded in the respective Safety Logs.

OC8B.5.3.3 The Implementing Safety Co-ordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting Safety Co-ordinator.

OC8B.5.3.4 Certain designs of gas insulated switchgear three position isolator and earth switches specifically provide a combined Isolation and Earthing function within a single mechanism contained within a single integral unit. Where Safety Precautions are required across control boundaries and subject to the requirements of OC8B.5.1, it is permissible to earth before Points of Isolation have been established provided that all interconnected circuits are fully disconnected from live HV Apparatus.

OC8B.5.4 RISSP Issue Procedure

OC8B.5.4.1 Where Safety Precautions on another System(s) are being provided to enable work on the Requesting Safety Co-ordinator’s System, before any work commences they must be recorded by a RISSP being issued. The RISSP is applicable to HV Apparatus up to the Connection Point (or, in the case of OTSUA, Transmission Interface Point) identified in section 1.1 of the RISSP-R and RISSP-I forms.

OC8B.5.4.2 Where Safety Precautions are being provided to enable work to be carried out on both sides of the Connection Point (or, in the case of OTSUA, Transmission Interface Point) a RISSP will need to be issued for each side of the Connection Point (or, in the case of OTSUA, Transmission Interface Point) with Relevant Scottish Transmission Licensee and the respective User each enacting the role of Requesting Safety Co-ordinator. This will result in a RISSP-R and a RISSP-I form being completed by each of the Relevant Scottish Transmission Licensee and the Scottish User, with each Requesting Safety Co-ordinator issuing a separate RISSP number.

OC8B.5.4.3 Once the Safety Precautions have been established (in accordance with OC8B.5.2 and OC8B.5.3), the Implementing Safety Co-ordinator shall complete parts 1.1 and 1.2 of a RISSP-I form recording the details specified in OC8B.5.1.3, OC8B.5.2.2 and OC8B.5.3.2. Where Earthing has not been requested, Part 1.2(b) will be completed with the words “not applicable” or “N/A”. They shall then contact the Requesting Safety Co-ordinator to pass on these details.

OC8B.5.4.4 The Requesting Safety Co-ordinator shall complete Parts 1.1 and 1.2 of the RISSP-R, making a precise copy of the details received. On completion, the Requesting Safety Co-ordinator shall read the entries made back to the sender and check that an accurate copy has been made.

OC8B.5.4.5 The Requesting Safety Co-ordinator shall then issue the number of the RISSP, taken from the RISSP-R, to the Implementing Safety Co-ordinator who will ensure that the number, including the prefix and suffix (where applicable), is accurately recorded in the designated space on the RISSP-I form.

OC8B.5.4.6 The Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator shall complete and sign Part 1.3 of the RISSP-R and RISSP-I respectively and then enter the time and date. When signed no alteration to the RISSP is permitted; the RISSP may only be cancelled.

OC8B.5.4.7 The Requesting Safety Co-ordinator is then free to authorise work, but not testing, in accordance with the requirements of the relevant internal safety procedures which apply to the Requesting Safety Co-ordinator’s System. This is likely to involve the issue of safety documents or other relevant internal authorisations. Where testing is to be carried out, the procedure set out below in OC8B.6 shall be implemented.
OC8B.5.5  RISSP Cancellation Procedure

OC8B.5.5.1  When the Requesting Safety Co-ordinator decides that Safety Precautions are no longer required, they will contact the relevant Implementing Safety Co-ordinator to effect cancellation of the associated RISSP.

OC8B.5.5.2  The Requesting Safety Co-ordinator will inform the relevant Implementing Safety Co-ordinator of the RISSP identifying number, including the prefix and suffix (where applicable), and agree it is the RISSP to be cancelled.

OC8B.5.5.3  The Requesting Safety Co-ordinator and the relevant Implementing Safety Co-ordinator shall then respectively complete Part 2.1 of their respective RISSP-R and RISSP-I forms and shall then exchange details. The details being exchanged shall include their respective names and time and date. On completion of the exchange of details the respective RISSP is cancelled. The removal of Safety Precautions is as set out in OC8B.5.5.4 and OC8B.5.5.5.

OC8B.5.5.4  Neither Safety Co-ordinator shall instruct the removal of any Isolation forming part of the Safety Precautions as part of the returning of the HV Apparatus to service until it is confirmed to each by each other that every earth on each side of the Connection Point (or, in the case of OTSUA, Transmission Interface Point), within the points of isolation identified on the RISSP, has been removed or disconnected by the provision of additional Points of Isolation.

OC8B.5.5.5  Subject to the provisions in OC8B.5.5.4, the Implementing Safety Co-ordinator is then free to arrange the removal of the Safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Co-ordinator is representing. Where a Key Safe Key has been given to the authorised site representative of the Requesting Safety Co-ordinator, the Key Safe Key must be returned to the authorised site representative of the Implementing Safety Co-ordinator. The only situation in which any Safety Precautions may be removed without first cancelling the RISSP in accordance with OC8B.5.5 or OC8B.5.6 is when Earthing is removed in the situation envisaged in OC8B.6.2(b).
OC8B.5.6  **RISSP Change Control**

Nothing in this OC8B prevents Relevant Scottish Transmission Licensees and Scottish Users agreeing to a simultaneous cancellation and issue of a new RISSP, if both agree. It should be noted, however, that the effect of that under the relevant Safety Rules is not a matter with which the Grid Code deals.

OC8B.6  **TESTING**

OC8B.6.1  The carrying out of the test may affect Safety Precautions on RISSPs or work being carried out which does not require a RISSP. Testing can, for example, include the application of an independent test voltage. Accordingly, where the Requesting Safety Co-ordinator wishes to authorise the carrying out of such a test to which the procedures in OC8B.6 apply, they may not do so and the test will not take place unless and until the steps in (a)-(c) below have been followed and confirmation of completion has been recorded in the respective Safety Logs:

(a) confirmation must be obtained from the Implementing Safety Co-ordinator that:

(i) no person is working on, or testing, or has been authorised to work on, or test, any part of its System or another System(s) (other than the System of the Requesting Safety Co-ordinator) within the points of Isolation identified on the RISSP form relating to the test which is proposed to be undertaken, and

(ii) no person will be so authorised until the proposed test has been completed (or cancelled) and the Requesting Safety Co-ordinator has notified the Implementing Safety Co-ordinator of its completion (or cancellation);

(b) any other current RISSPs which relate to the parts of the System in which the testing is to take place must have been cancelled in accordance with procedures set out in OC8B.5.5;

(c) the Implementing Safety Co-ordinator must agree with the Requesting Safety Co-ordinator to permit the testing on that part of the System between the points of Isolation identified in the RISSP associated with the test and the points of Isolation on the Requesting Safety Co-ordinator’s System.

OC8B.6.2  (a) The Requesting Safety Co-ordinator will inform the Implementing Safety Co-ordinator as soon as the test has been completed or cancelled and the confirmation shall be recorded in the respective Safety Logs.

(b) When the test gives rise to the removal of Earthing which it is not intended to re-apply, the relevant RISSP associated with the test shall be cancelled at the completion or cancellation of the test in accordance with the procedure set out in either OC8B.5.5 or OC8B.5.6. Where the Earthing is re-applied following the completion or cancellation of the test, there is no requirement to cancel the relevant RISSP associated with the test pursuant to this OC8B.6.2.

OC8B.7  **EMERGENCY SITUATIONS**

OC8B.7.1  There may be circumstances where Safety Precautions need to be established in relation to an unintended electrical connection or situations where there is an unintended risk of electrical connection between the National Electricity Transmission System and a Scottish User’s System, for example resulting from an incident where one line becomes attached or unacceptably close to another.

OC8B.7.2  In those circumstances, if both the Relevant Scottish Transmission Licensee and the Scottish User agree, the relevant provisions of OC8B.5 will apply as if the electrical connections or potential connections were, solely for the purposes of this OC8B, a Connection Point (or, in the case of OTSUA, Transmission Interface Point).
OC8B.7.3 (a) The relevant Safety Co-ordinator shall be that for the electrically closest existing Connection Point (or, in the case of OTSUA, Transmission Interface Point) to that Scottish User’s System or such other local Connection Point (or, in the case of OTSUA, Transmission Interface Point) as may be agreed between the Relevant Scottish Transmission Licensee and the Scottish User, with discussions taking place between the relevant local Safety Co-ordinators. The Connection Point (or, in the case of OTSUA, Transmission Interface Point) to be used shall be known in this OC8B.7.3 as the "relevant Connection Point" (or, in the case of OTSUA, relevant "Transmission Interface Point").

(b) The Safety Rules shall be those which apply to the relevant Connection Point (or, in the case of OTSUA, Transmission Interface Point).

(c) The prefix for the RISSP (where applicable) will be that which applies for the relevant Connection Point (or, in the case of OTSUA, Transmission Interface Point).

OC8B.8 SAFETY PRECAUTIONS RELATING TO WORKING ON EQUIPMENT NEAR TO THE HV SYSTEM

OC8B.8 applies to the situation where work is to be carried out at a Scottish User’s Site or a Transmission Site (as the case may be) on equipment of the Scottish User or a Relevant Scottish Transmission Licensee as the case may be, where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System. It does not apply to other situations to which OC8B applies. In this part of OC8B, a Permit for Work for proximity work is to be used, rather than the usual RISSP procedure, given the nature and effect of the work, all as further provided in the OC8B.8.

OC8B.8.1 Agreement Of Safety Precautions

OC8B.8.1.1 The Requesting Safety Co-ordinator who requires Safety Precautions on another System(s) when work is to be carried out at a Scottish User’s Site or a Transmission Site (as the case may be) on equipment of the Scottish User or a Relevant Scottish Transmission Licensee, as the case may be, where the work or equipment is near to HV Apparatus on the Implementing Safety Co-ordinator’s System will contact the relevant Implementing Safety Co-ordinator(s) to agree the Location of the Safety Precautions to be established, having as part of this process informed the Implementing Safety Co-ordinator of the equipment and the work to be undertaken. The respective Safety Co-ordinators will ensure that they discuss the request with their authorised site representative and that the respective authorised site representatives discuss the request at the Connection Site (or, in the case of OTSUA, Transmission Interface Site). This agreement will be recorded in the respective Safety Logs.

OC8B.8.1.2 It is the responsibility of the Implementing Safety Co-ordinator, working with their authorised site representative as appropriate, to ensure that adequate Safety Precautions are established and maintained, on their and/or another System connected to their System, to enable Safety From The System to be achieved for work to be carried out at a Scottish User’s Site or a Transmission Site (as the case may be) on equipment and in relation to work which is to be identified in the relevant part of the Permit for Work for proximity work where the work or equipment is near to HV Apparatus of the Implementing Safety Co-ordinator’s System specified by the Requesting Safety Co-ordinator. Reference to another System in this OC8B.8.1.2 shall not include the Requesting Safety Co-ordinator’s System.

OC8B.8.1.3 In The Event Of Disagreement

In any case where the Requesting Safety Co-ordinator and the Implementing Safety Co-ordinator are unable to agree the Location of the Isolation and (if requested) Earthing, both shall be at the closest available points on the infeeds to the HV Apparatus near to which the work is to be carried out as indicated on the Operation Diagram.

OC8B.8.2 Implementation Of Isolation And Earthing
Following the agreement of the Safety Precautions in accordance with OC8B.8.1, the Implementing Safety Co-ordinator shall then establish the agreed Isolation and (if required) Earthing.

The Implementing Safety Co-ordinator shall confirm to the Requesting Safety Co-ordinator that the agreed Isolation and (if required) Earthing has been established.

The Implementing Safety Co-ordinator shall ensure that the established Safety Precautions are maintained until requested to be removed by the relevant Requesting Safety Co-ordinator.

Permit For Work For Proximity Work Issue Procedure

Where Safety Precautions on another System(s) are being provided to enable work to be carried out at a Scottish User’s Site or Transmission Site (as the case may be) on equipment where the work or equipment is in proximity to HV Apparatus of the Implementing Safety Co-ordinator, before any work commences they must be recorded by a Permit for Work for proximity work being issued. The Permit for Work for proximity work shall identify the Implementing Safety Co-ordinator’s HV Apparatus in proximity to the required work.

Once the Safety Precautions have been established (in accordance with OC8B.8.2), the Implementing Safety Co-ordinator shall agree to the issue of the Permit for Work for proximity work with the appropriately authorised site representative of the Requesting Safety Co-ordinator’s Site. The Implementing Safety Co-ordinator will inform the Requesting Safety Co-ordinator of the Permit for Work for proximity work identifying number.

The appropriately authorised site representative of the Implementing Safety Co-ordinator shall then issue the Permit for Work for proximity work to the appropriately authorised site representative of the Requesting Safety Co-ordinator. The Permit for Work for proximity work will in the section dealing with the work to be carried out, be completed to identify that the work is near the Implementing Safety Co-ordinator’s HV Apparatus. No further details of the Requesting Safety Co-ordinator’s work will be recorded, as that is a matter for the Requesting Safety Co-ordinator in relation to their work.

The Requesting Safety Co-ordinator is then free to authorise work in accordance with the requirements of the relevant internal safety procedures which apply to the Requesting Safety Co-ordinator’s Site. This is likely to involve the issue of safety documents or other relevant internal authorisations.

Permit For Work For Proximity Work Cancellation Procedure

When the Requesting Safety Co-ordinator decides that Safety Precautions are no longer required, they will contact the relevant Implementing Safety Co-ordinator to effect cancellation of the associated Permit for Work for proximity work.

The Requesting Safety Co-ordinator will inform the relevant Implementing Safety Co-ordinator of the Permit for Work for proximity work identifying number, and agree that the Permit for Work for proximity work can be cancelled. The cancellation is then effected by the appropriately authorised site representative of the Requesting Safety Co-ordinator returning the Permit for Work for proximity work to the appropriately authorised site representative of the Implementing Safety Co-ordinator.

The Implementing Safety Co-ordinator is then free to arrange the removal of the Safety Precautions, the procedure to achieve that being entirely an internal matter for the party the Implementing Safety Co-ordinator is representing.
OC8B.9 LOSS OF INTEGRITY OF SAFETY PRECAUTIONS

OC8B.9.1 In any instance when any Safety Precautions may be ineffective for any reason, the relevant Safety Co-ordinator shall inform the other Safety Co-ordinator(s) without delay of that being the case and, if requested, of the reasons why.

OC8B.10 SAFETY LOG

OC8B.10.1 Relevant Scottish Transmission Licensees and Scottish Users shall maintain Safety Logs which shall be a chronological record of all messages relating to safety co-ordination under OC8 sent and received by the Safety Co-ordinator(s). The Safety Logs must be retained for a period of not less than six years.
APPENDIX A - RISSP-R

RECORD OF INTER-SYSTEM SAFETY PRECAUTIONS (RISSP-R)
(Requesting Safety Co-ordinator's Record)

RISSP NUMBER __________

Part 1

1.1 CIRCUIT IDENTIFICATION

Safety Precautions have been established by the Implementing Safety Co-ordinator to achieve Safety From The System on the following HV Apparatus:

________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________

1.2 SAFETY PRECAUTIONS ESTABLISHED

(a) ISOLATION

State the Locations(s) at which Isolation has been established on the Implementing Safety Co-ordinator's System. For each Location, identify each point of Isolation. For each point of Isolation state, the means by which the Isolation has been achieved, and whether, immobilised and Locked, Caution Notice affixed, other Safety Precautions applied, as appropriate.

________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________


(b) **EARTHING**

State the Locations(s) at which Earthing has been established on the Implementing Safety Co-ordinator's System. For each Location, identify each point of Earthing. For each point of Earthing state, the means by which the Earthing has been achieved, and whether, immobilised and Locked, other Safety Precautions applied, as appropriate.

________________________________________________________________________

________________________________________________________________________

________________________________________________________________________

________________________________________________________________________

________________________________________________________________________

________________________________________________________________________

1.3 **ISSUE**

I have received confirmation from ____________________ (name of Implementing Safety Co-ordinator) at ____________________ (Location) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at their Location for their removal until this RISSP is cancelled.

Signed ................................................... (Requesting Safety Co-ordinator)

at ............................. (time) on ....................................... (date)

**PART 2**

2.1 **CANCELLATION**

I have confirmed to ____________________ (name of the Implementing Safety Co-ordinator) at ____________________ (Location) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly the RISSP is cancelled.

Signed ................................................... (Requesting Safety Co-ordinator)

at ............................. (time) on ....................................... (date)
APPENDIX B - RISSP-I

RECORD OF INTER-SYSTEM SAFETY PRECAUTIONS (RISSP-I)
(Implementing Safety Co-ordinator's Record)

RISSP NUMBER __________

PART 1

1.1 CIRCUIT IDENTIFICATION

Safety Precautions have been established by the Implementing Safety Co-ordinator to achieve Safety From The System on the following HV Apparatus:

________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________

1.2 SAFETY PRECAUTIONS ESTABLISHED

(a) ISOLATION

State the Location(s) at which isolation has been established on the Implementing Safety Co-ordinator's System. For each Location, identify each point of Isolation. For each point of Isolation state, the means by which the Isolation has been achieved, and whether, immobilised and Locked, Caution Notice affixed, other Safety Precautions applied, as appropriate.

________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________

No text is available for inclusion in APPENDIX A.
(b) **EARTHING**

State the Location(s) at which Earthing has been established on the Implementing Safety Co-ordinator's System. For each Location, identify each point of Earthing. For each point of Earthing state, the means by which the Earthing has been achieved, and whether, immobilised and Locked, other Safety Precautions applied, as appropriate.

________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________
________________________________________________________________

1.3 **ISSUE**

I confirmed to ____________________ (name of Requesting Safety Co-ordinator) at ____________________ (Location) that the Safety Precautions identified in paragraph 1.2 have been established and that instructions will not be issued at my Location for their removal until this RI SSP is cancelled.

Signed .................................................. (Implementing Safety Co-ordinator)

at ................................. (time) on ........................... (date)

**PART 2**

2.1 **CANCELLATION**

I have received confirmation from ____________________ (name of the Requesting Safety Co-ordinator) at ____________________ (Location) that the Safety Precautions set out in paragraph 1.2 are no longer required and accordingly the RI SSP is cancelled.

Signed .................................................. (Implementing Safety Co-ordinator)

at ................................. (time) on ........................... (date)

(Note: This form to be of a different colour from RI SSP-R.)
Where testing affects another Safety Co-ordinator's System

Continue from OC8B Appendix C1

Testing will not take place by RSC until:

OC8B.6.1

Requesting Safety Co-ordinator (RSC)
Person requiring Safety Precaution from another User

Implementing Safety Co-ordinator (ISC)
Person who co-ordinates provision of Safety Precautions

ISC confirms that no person is working or testing or authorised to, on his System or another System within the points of isolation on the RISSP

Log
OC8B.6.1(a)(i)

No person will be so authorised until proposed test is completed (or cancelled) by the RSC

OC8B.6.1(a)(ii)

Any RISSP other than for the proposed test shall be cancelled

OC8B.6.1(b)

The ISC agrees to the testing between the points of isolation on the RISSP and the RSC System

OC8B.6.1(c)

Test can now take place

When test is complete or cancelled, RSC informs ISC

Log
OC8B.6.2(a)

If testing required the removal of earthing the RISSP process is as set out in:

OC8B.6.2(b)

Earthing reapplied

OC8B.6.2(b)

Earthing not reapplied

OC8B.5.2(b)

RISSP cancellation process. See OC8B Appendix C3

RISSP can stay in force, if required
APPENDIX C3 - RISSP CANCELLATION PROCESS

- **Requesting Safety Co-ordinator (RSC)**
  - Person requiring Safety Precaution from another User

- **Implementing Safety Co-ordinator (ISC)**
  - Person who co-ordinates provision of Safety Precautions

Work/Testing completed or cancelled

RSC contacts ISC to inform safety precautions are no longer required

RSC informs ISC of RISSP document to be cancelled (including identity numbers)

The RSC and ISC complete their respective parts of section 2.1 on RISSP-R and RISSP-I

RISSP is now canceled

Agree removal of Safety Precautions

Removal of earthing during testing across the Connection Point/Transmission Interface Point is as set out in:

- OC8B.5.2(b)

Agreed between RSC and ISC that all earths are removed

Removal of isolation agreed between RSC and ISC

OC8B process complete

Removal being an internal matter for the party the ISC represents
**Requesting Safety Co-ordinator (RSC)**  
Person requiring Safety Precaution from another User

**Implementing Safety Co-ordinator (ISC)**  
Person who co-ordinates provision of Safety Precautions

---

Work/Testing completed or cancelled

- RSC contacts ISC to inform safety precautions are no longer required  
  - OC8B 5.5.1

- RSC informs ISC of RISSP document to be cancelled (including identity numbers)  
  - OC8B 5.5.2

---

The RSC and ISC complete their respective parts of section 2.1 on RISSP-R and RISSP-I  
- OC8B 5.5.3

---

The RSC and ISC exchange the details including respective names, times and date  
- OC8B 5.5.3

---

RISSP is now cancelled  
- OC8B 5.5.3

---

Agree removal of Safety Precautions

---

Removal of earthing during testing across the Connection Point/Transmission Interface Point is as set out in:  
- OC8B 5.2(0)

---

Agreed between RSC and ISC that all earths are removed  
- OC8B 5.5.4

Removal of isolation agreed between RSC and ISC  
- OC8B 5.5.4

---

Removal being an internal matter for the party the ISC represents  
- OC8B 5.5.5

---

OC8B process complete
APPENDIX D - NOT USED

Not Used
APPENDIX E - FORM OF PERMIT TO WORK

Scottish & Southern Energy plc

PERMIT-TO-WORK No. ………………………

1. ISSUE

To …………………………………………………………………………………………………………………………………………………..

The following High Voltage Apparatus has been made safe in accordance with the Operational Safety Rules for the work detailed on this Permit-to-Work to proceed:
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..

TREAT ALL OTHER APPARATUS AS LIVE

Circuit Main Earths are applied at: …………………………………………………………………………………………………………
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..

Other precautions (see Operational Safety Rules 3.2.1(b), 4.6.2(c) and 5.5.3), and any special instructions:
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..

The following work is to be carried out: ………………………………………………………………………………………………………
……………………………………………………………………………………………………………………………………………………………..
……………………………………………………………………………………………………………………………………………………………..

Circuit Identification Issued: Colour …….. No. of wristlets …….. No. of step bolts ……..
Name: (print): ………………..…..…..   Signature: ………..…...………. Time: ……….………….. Date: …….

_____________________________________________________________________________________________

2. RECEIPT

I accept responsibility for carrying out the work on the Apparatus detailed on this Permit-to-Work, applying additional earths as necessary. No attempt will be made by me, or by the persons under my charge, to work on any other Apparatus.

Name: (print): ………………..…..…..   Signature: ………..…...………. Time: ……….………….. Date: …….

Circuit Identification Equipment Checked as above (Initials): ……………………

_______________________________________________________________________________________

3. CLEARANCE

All persons under my control have been withdrawn and warned that it is no longer safe to work on the Apparatus detailed on this Permit-to Work.

All gear, tools and additional earths have/have not* been removed. The works is/is not* complete.

All circuit identification equipment issued as above has been returned

Name: (print): ………………..…..…..   Signature: ………..…...………. Time: ……….………….. Date: …….

* Delete where not applicable

_____________________________________________________________________________________________

4. CANCELLATION

This Permit-to-Work is cancelled.

Name: (print): ………………..…..…..   Signature: ………..…...………. Time: ……….………….. Date: …….

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Scottish Power

PERMIT FOR WORK

1. (i) LOCATION .................................................................................................................................

(ii) PLANT/APPARATUS IDENTIFICATION ..................................................................................

(iii) WORK TO BE DONE ................................................................................................................

2. (i) PRECAUTIONS TAKEN TO ACHIEVE SAFETY FROM THE SYSTEM: State points at which Plant/Apparatus has been isolated and specify position(s) of Earthing Devices applied. State actions taken to avoid Danger by draining, venting, purging and containment or dissipation of stored energy.

(ii) FURTHER PRECAUTIONS TO BE TAKEN DURING THE COURSE OF WORK TO AVOID SYSTEM DERIVED HAZARDS

Caution Notices have been affixed to all points of isolation

I have confirmed with the Control Person(s)* .................................................................................... that precautions in Section 2(i) have been carried out and that the Control Person(s) will maintain these until this Permit for Work is cancelled. I certify that the precautions in Section 2(i) together with the precautions in Section 2(ii) are adequate to provide Safety from the System in respect of the work in Section 1.

This Permit for Work must only be transferred under the Personal Supervision of a Senior Authorised Person*

Signed ................................................................ being a Senior Authorised Person. Time: .......... Date: ..........

3. ISSUE

(i) Key Safe Key (No.)* .... (ii) Earthing Schedule* .... (iii) Portable Drain Earths (No. off)* ....

(iv) Selected Person’s Report (No.)* ................................ (v) Circuit Identification Flags (No. off)*

(vi) Circuit Identification Wristlets (No. off)* and Colours/Symbols ........................................

Signed ................................................................ being the Senior Authorised Person responsible

for the issue of this Permit for Work Time: .... Date: ...........
4. RECEIPT
I understand and accept my responsibilities under the ScottishPower Safety Rules as recipient of this Permit for Work and acknowledge receipt of the items in Section 3.

Signed .............................................. Name (Block Letters) ..........................................................

being a Competent Person in the employ of Firm/Dept ............................... Time ........ Date ........

__________________________________________________________

TRANSFER RECORD

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*Signature of Person receiving re-issued Document in accordance with conditions detailed in Section 4.

5. CLEARANCE: I certify that all persons working under this Permit for Work have been withdrawn from, and warned not to work on, the Plant/Apparatus in Section 1. All gears, tools, Drain Earths and loose material have been removed and guards and access doors have been replaced, except for:

………………………………………………………………………………………………………………………………………………

………………………………………………………………………………………………………………………………………………

Signed .............................................. being the Competent Person responsible for

clearing this Permit for Work Time ........ Date ........

6. CANCELLATION: I certify that all items issued under Section 3 have been accounted for and the Control Person(s)* ................................................ informed of the cancellation and of any restrictions on returning
the Plant/Apparatus to service.

Signed .............................................. being the Senior Authorised Person responsible for

cancelling this Permit for Work. Time ........ Date ........

*N/A if Not Applicable

< END OF OPERATING CODE NO. 8 APPENDIX 2 >
## OPERATING CODE NO. 9
(OC9)

**CONTINGENCY PLANNING**

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OC9.1 INTRODUCTION

Operating Code No.9 ("OC9") covers the following:

OC9.1.1 Black Starts

The implementation of recovery procedures following a Total Shutdown or Partial Shutdown.

OC9.1.2 Re-Synchronisation Of Islands

The Re-Synchronisation of parts of the Total System which have become Out of Synchronism with each other irrespective of whether or not a Total Shutdown or Partial Shutdown has occurred.

OC9.1.3 Joint System Incident Procedure

The establishment of a communication route and arrangements between senior management representatives of The Company and Users involved in, or who may be involved in, an actual or potential serious or widespread disruption to the Total System or a part of the Total System, which requires, or may require, urgent managerial response, day or night, but which does not fall within the provisions of OC9.1.4.

OC9.1.4 It should be noted that under section 96 of the Act, the Secretary of State may give directions to The Company and/or any Generator and/or any Supplier, for the purpose of "mitigating the effects of any civil emergency which may occur" (ie. for the purposes of planning for a civil emergency); a civil emergency is defined in the Act as "any natural disaster or other emergency which, in the opinion of the Secretary of State, is or may be likely to disrupt electricity supplies". Under the Energy Act 1976, the Secretary of State has powers to make orders and give directions controlling the production, supply, acquisition or use of electricity, where an Order in Council under section 3 is in force declaring that there is an actual or imminent emergency affecting electricity supplies. In the event that any such directions are given, or orders made under the Energy Act 1976, the provisions of the Grid Code will be suspended in so far as they are inconsistent with them.

OC9.1.5 The Company shall procure that Relevant Transmission Licensees shall comply with OC9.4 and OC9.5 and any relevant Local Joint Restoration Plan or OC9 De-Synchronised Island Procedure where and to the extent that such matters apply to them.

OC9.2 OBJECTIVE

The overall objectives of OC9 are:

OC9.2.1 To achieve, as far as possible, restoration of the Total System and associated Demand in the shortest possible time, taking into account Power Station capabilities, including Embedded Generating Units, External Interconnections and the operational constraints of the Total System.
To achieve the **Re-Synchronisation** of parts of the **Total System** which have become **Out of Synchronism** with each other.

To ensure that communication routes and arrangements are available to enable senior management representatives of **The Company** and **Users**, who are authorised to make binding decisions on behalf of **The Company** or the relevant **User**, as the case may be, to communicate with each other in the situation described in OC9.1.3.

To describe the role that in respect of **Transmission Systems**, **Relevant Transmission Licensees** may have in the restoration processes as detailed in the relevant **OC9 De-Synchronised Island Procedures** and **Local Joint Restoration Plans**.

To identify and address as far as possible the events and processes necessary to enable the restoration of the **Total System**, after a **Total Shutdown** or **Partial Shutdown**. This is likely to require the following key processes to be implemented, typically, but not necessarily, in the order given below:

(i) Selectively implement **Local Joint Restoration Plans**

(ii) Expand **Power Islands** to supply **Power Stations**

(iii) Expand and merge **Power Islands** leading to **Total System** energisation

(iv) Selectively reconnect **Demand**

(v) Facilitate and co-ordinate returning the **Total System** back to normal operation

(vi) Resumption of the **Balancing Mechanism** if suspended in accordance with the provisions of the **BSC**.

**SCOPE**

**OC9** applies to **The Company** and to **Users**, which in **OC9** means:-

(a) **Generators**;

(b) **Network Operators**; and

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

The procedure for the establishment of emergency support/contingency planning between **The Company** and **Externally Interconnected System Operators** is set out in the **Interconnection Agreement** with each **Externally Interconnected System Operator**.

In respect of **Transmission Systems**, **OC9.4** and **OC9.5** also apply to **Relevant Transmission Licensees**.

**BLACK START**

**Total Shutdown And Partial Shutdown**

A **"Total Shutdown"** is the situation existing when all generation has ceased and there is no electricity supply from **External Interconnections**. 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**.
A "Partial Shutdown" is 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. 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.

During a Total Shutdown or Partial Shutdown and during the subsequent recovery, the Licence Standards may not apply and the Total System may be operated outside normal voltage and Frequency standards.

In a Total Shutdown and in a Partial Shutdown and during the subsequent recovery, it is likely to be necessary for The Company to issue Emergency Instructions in accordance with BC2.9.

Black Start Service Providers

Black Start Service Providers are registered pursuant to the Bilateral Agreement as having the capability to Start-Up from Shutdown and to energise a part of the Total System, or be Synchronised to the System, upon instruction from The Company within two hours, without an external electrical power supply ("Black Start Capability").

For each Black Start Station and Black Start HVDC System, a Local Joint Restoration Plan will be produced jointly by The Company, the relevant Black Start Service Provider and Network Operator in accordance with the provisions of OC9.4.7.12. The Local Joint Restoration Plan will detail the agreed method and procedure by which a Genset at a Black Start Station (possibly with other Gensets at that Black Start Station) and Black Start HVDC Systems will energise part of the Total System and meet complementary local Demand so as to form a Power Island.

In respect of Scottish Transmission Systems, a Local Joint Restoration Plan may cover more than one Black Start Station or Black Start HVDC System and may be produced with and include obligations on Relevant Scottish Transmission Licensees, Generators responsible for Gensets not at a Black Start Station and other Users including HVDC System Owners and DC Converter Station Owners.

Black Start Situation

In the event of a Total Shutdown or Partial Shutdown, The Company will, as soon as reasonably practical, inform Users (or, in the case of a Partial Shutdown, Users which in The Company's opinion need to be informed) and the BSCCo that a Total Shutdown, or, as the case may be, a Partial Shutdown, exists and that The Company intends to implement a Black Start. The Company shall (as soon as is practicable) determine, in its reasonable opinion, the time and date with effect from which the Total Shutdown or Partial Shutdown commenced and notify the BSCCo of that time and date.

In the event of a Total Shutdown and following such notification, in accordance with the provisions of the BSC, the BSCCo will determine the Settlement Period with effect from which the Balancing Mechanism is suspended.
In the event of a Partial Shutdown and following such notification, the Balancing Mechanism will not be suspended until such time and date that the Market Suspension Threshold has been met, or deemed to have been met, in accordance with the provisions of the BSC. The Company shall carry out the monitoring activities required by paragraph G3.1 of the BSC.

Following determination by The Company pursuant to its obligations under the BSC that the Market Suspension Threshold has been met, or deemed to have been met, The Company shall (as soon as practicable) inform the BSCCo of that time and date at which the Market Suspension Threshold was met, or deemed to have been met, and the BSCCo will determine the Settlement Period in accordance with the provisions of the BSC with effect from which the Balancing Mechanism will be suspended.

Should The Company determine that the Total System is capable of returning to normal operation without meeting the Market Suspension Threshold, The Company will follow the procedure given in OC9.4.7.9.

The Black Start will conclude with effect from the time and date determined in accordance with OC9.4.7.10.

In respect of Scottish Transmission Systems, in exceptional circumstances, as specified in the Local Joint Restoration Plan, SPT or SHETL, may invoke such Local Joint Restoration Plan for its own Transmission System and Scottish Offshore Transmission Systems connected to it and operate within its provisions.

**OC9.4.7** Black Start

**OC9.4.7.1** The procedure necessary for a recovery from a Total Shutdown or Partial Shutdown is known as a "Black Start". The procedure for a Partial Shutdown is the same as that for a Total Shutdown except that it applies only to a part of the Total System. It should be remembered that a Partial Shutdown may affect parts of the Total System which are not themselves shutdown.

**OC9.4.7.2** The complexities and uncertainties of recovery from a Total Shutdown or Partial Shutdown require that OC9 is sufficiently flexible in order to accommodate the full range of User’s Plant and Apparatus and Total System characteristics and operational possibilities, and this precludes the setting out in the Grid Code itself of concise chronological sequences. The overall strategy will, in general, include the overlapping phases of establishment of Genset(s), at an isolated Power Station, or isolated HVDC System or isolated DC Converter Station, together with complementary local Demand, termed ‘Power Islands’, step by step integration of these Power Islands into larger sub-systems which includes utilising the procedures in OC9.5 (Re-Synchronisation of De-Synchronised Island) and eventually re-establishment of the complete Total System.

The Company Instructions

**OC9.4.7.3** The procedures for a Black Start will, therefore, be those specified by The Company at the time. These will normally recognise any applicable Local Joint Restoration Plan. Users shall abide by The Company’s instructions during a Black Start situation, even if these conflict with the general overall strategy outlined in OC9.4.7.2 or any applicable Local Joint Restoration Plan. The Company’s instructions may (although this list should not be regarded as exhaustive) be to a Black Start Station or Black Start HVDC System relating to the commencement of supplying Active Power, to a Network Operator or Non-Embedded Customer relating to the restoration of Demand, and to a
Power Station or HVDC System or DC Converter Station relating to preparation for commencement of supplying Active Power when an external power supply is made available to it, and in each case may include the requirement to undertake switching.

In respect of Scottish Transmission Systems, SPT and SHETL will act on The Company’s behalf in accordance with its duties under the relevant Local Joint Restoration Plan. Scottish Users shall abide by SPT’s or SHETL’s instructions given in accordance with the Local Joint Restoration Plan during a Black Start situation.

(a) **Black Start** following a Total Shutdown or where the Balancing Mechanism has been suspended following a Partial Shutdown

During a **Black Start** situation where the Balancing Mechanism has been suspended, all instructions to Users will be deemed to be Emergency Instructions under BC2.9.2.2 (iii). All such Emergency Instructions will recognise any differing Black Start operational capabilities (however termed) set out in the relevant Ancillary Services Agreement in preference to the declared operational capability as registered pursuant to BC1 (or as amended from time to time in accordance with the BC). For the purposes of these instructions the **Black Start** will be an emergency circumstance under BC2.9.

In Scotland, Gensets or HVDC Systems or DC Converter Station that are not at Black Start Stations or Black Start HVDC Systems, but which are part of a Local Joint Restoration Plan, may be instructed in accordance with the provisions of that Local Joint Restoration Plan.

(b) **Black Start** following a Partial Shutdown where the Balancing Mechanism has not been suspended

During a **Black Start** situation where the Balancing Mechanism has not been suspended, instructions in relation to Black Start Stations and to Network Operators, Black Start HVDC Systems which are part of an invoked Local Joint Restoration Plan will (unless The Company specifies otherwise) be deemed to be Emergency Instructions under BC2.9.2.2 (iv) and will recognise any differing Black Start operational capabilities (however termed) set out in the relevant Ancillary Services Agreement in preference to the declared operational capability as registered pursuant to BC1 (or as amended from time to time in accordance with the BC). For the purposes of these instructions the **Black Start** will be an emergency circumstance under BC2.9.

During a **Black Start** situation where the Balancing Mechanism has not been suspended, The Company may issue instructions to Users other than Black Start Stations and Network Operators which are part of an invoked Local Joint Restoration Plan. Such instructions would be Emergency Instructions pursuant to BC2.9.1.2(e)(i) subject to the requirements of BC2.9.2.2 being met.

In Scotland, Gensets and HVDC Systems or DC Converter Station that are not at Black Start Stations or Black Start HVDC Systems, but which are part of an invoked Local Joint Restoration Plan, may be instructed in accordance with the provisions of that Local Joint Restoration Plan.

(c) **Requirements to inform The Company** where a Genset, HVDC System or DC Converter cannot operate within its safe operating limits during the Demand restoration process.
If during the Demand restoration process any Genset or HVDC System or DC Converter Station cannot, because of the Demand being experienced, keep within its safe operating parameters, the Black Start Service Provider shall, unless a Local Joint Restoration Plan is in operation, inform The Company. The Company will, where possible, either instruct Demand to be altered or will re-configure the National Electricity Transmission System or will instruct a User to re-configure its System in order to alleviate the problem being experienced by the Genset or HVDC System or DC Converter Station. If a Local Joint Restoration Plan is in operation, then the arrangements set out therein shall apply. However, The Company accepts that any decision to keep a Genset or HVDC System or DC Converter Station operating, if outside its safe operating parameters, is one for the Black Start Service Providers concerned alone and accepts that the Black Start Service Provider may change output on that Genset or HVDC System or DC Converter Station if it believes it is necessary for safety reasons (whether relating to personnel or Plant and/or Apparatus). If such a change is made without prior notice, then the Black Start Service Provider shall inform The Company as soon as reasonably practical (unless a Local Joint Restoration Plan is in operation in which case the arrangements set out therein shall apply).

**Embedded Power Stations**

OC9.4.7.5 Without prejudice to the provisions of OC9.4.7.8, Network Operators with Embedded Power Stations or Embedded HVDC Systems or Embedded DC Converter Stations will comply with any directions of The Company to restore Demand to be met by the Embedded Power Stations, Embedded HVDC Systems or Embedded DC Converter Stations.

**Local Joint Restoration Plan operation**

OC9.4.7.6 (a) The following provisions apply in relation to a Local Joint Restoration Plan. As set out in OC9.4.7.3, The Company may issue instructions which conflict with a Local Joint Restoration Plan. In such cases, these instructions will take precedence over the requirements of the Local Joint Restoration Plan. When issuing such instructions, The Company shall state whether or not it wishes the remainder of the Local Joint Restoration Plan to apply. If, not withstanding that The Company has stated that it wishes the remainder of the Local Joint Restoration Plan to apply, the Black Start Service Provider or the relevant Network Operator consider that The Company's instructions mean that it is not possible to operate the Local Joint Restoration Plan as modified by those instructions, any of them may give notice to The Company and the other parties to the Local Joint Restoration Plan to this effect and The Company shall immediately consult with all parties to the Local Joint Restoration Plan. Unless all parties to the Local Joint Restoration Plan reach an agreement forthwith as to how the Local Joint Restoration Plan shall operate in those circumstances, operation in accordance with the Local Joint Restoration Plan will terminate.

(b) Where The Company, as part of a Black Start, has given an instruction to a Black Start Service Provider to initiate Start-Up, the relevant Genset(s) at the Black Start Station or Black Start HVDC System will Start-Up in accordance with the Local Joint Restoration Plan.

(c) The Company will advise the relevant Network Operator of the requirement to switch its User System so as to segregate its Demand and to carry out such other actions as set out in the Local Joint Restoration Plan. The relevant Network
Operator will then operate in accordance with the provisions of the Local Joint Restoration Plan.

(d) The Company will ensure that switching carried out on the National Electricity Transmission System and other actions are as set out in the Local Joint Restoration Plan.

(e) Following notification from the Black Start Service Provider that the Black Start Station or Black Start HVDC System is ready to accept load, The Company will instruct the Black Start Service Provider to energise part of the Total System. The Black Start Service Provider and the relevant Network Operator will then, in accordance with the requirements of the Local Joint Restoration Plan, establish communication and agree the output of the relevant Genset(s) and/or HVDC System and/or DC Converter Station and the connection of Demand so as to establish a Power Island. During this period, the Black Start Service Provider will be required to regulate the output of the relevant Black Start Station or Black Start HVDC System to the Demand prevailing in the Power Island in which it is situated, on the basis that it will (where practicable) seek to maintain the Target Frequency. The Genset(s) at the Black Start Station or Black Start HVDC System will (where practical) also seek to follow the requirements relating to Reactive Power (which may include the requirement to maintain a target voltage) set out in the Local Joint Restoration Plan.

(f) Operation in accordance with the Local Joint Restoration Plan will be terminated by The Company (by notifying the relevant Users) prior to connecting the Power Island to other Power Islands (other than, in Scotland, as allowed for in the Local Joint Restoration Plan), or to the User System of another Network Operator, or to the synchronising of Gensets at other Power Stations or HVDC Systems or DC Converter Station (other than, in Scotland, those forming part of the Local Joint Restoration Plan). Operation in accordance with the Local Joint Restoration Plan will also terminate in the circumstances provided for in OC9.4.7.6(a) if an agreement is not reached or if The Company states that it does not wish the remainder of the Local Joint Restoration Plan to apply. Users will then comply with the Bid-Offer Acceptances or Emergency Instructions of The Company.

(g) In Scotland, Gensets or HVDC Systems or DC Converter Station included in a Local Joint Restoration Plan, but not at a Black Start Station or Black Start HVDC System, will operate in accordance with the requirements of the Local Joint Restoration Plan.

Interconnection of Power Islands

OC9.4.7.7 The Company will instruct the relevant Users so as to interconnect Power Islands to achieve larger sub-systems, and subsequently the interconnection of these sub-systems to form an integrated system. This should eventually achieve the re-establishment of the Total System or that part of the Total System subject to the Partial Shutdown, as the case may be. The interconnection of Power Islands and sub-systems will utilise the provisions of all or part of OC9.5 (Re-Synchronisation of De-synchronised Islands) and in such a situation such provisions will be part of the Black Start.

OC9.4.7.8 As part of the Black Start strategy, each Network Operator with either an Embedded Black Start Station or Embedded HVDC System or Embedded DC Converter Station, which has established a Power Island within its User System or with any Embedded Power Stations or Embedded HVDC Systems or Embedded DC Converter Stations within its User System, which have become islanded, may in liaison with The Company, sustain and expand these islands in accordance with the
relevant provisions of OC9.5 which shall apply to this OC9.4 as if set out here. They will inform The Company of their actions and will not Re-Synchronise to the National Electricity Transmission System or any User’s System which is already Synchronised to the National Electricity Transmission System without The Company’s agreement.

Return the Total System Back to Normal Operation

**OC9.4.7.9**
The Company shall, as soon as reasonably practical, inform Users and the BSCCo when the Total System could return to normal operation. Any such determination by The Company does not mean that the provisions of Section G paragraph 3 (Black Start) of the BSC shall cease to apply.

In making the determination that the Total System could return to normal operation, The Company, would consider, amongst other things, the following areas:

(a) the extent to which the National Electricity Transmission System is contiguous and energised;

(b) the integrity and stability of the National Electricity Transmission System and its ability to operate in accordance with the Licence Standards;

(c) the impact that returning to normal may have on transmission constraints and the corresponding ability to maximise the Demand connected; and

(d) the volume of generation, Electricity Storage or Demand not connected to the National Electricity Transmission System; and

(e) the functionality of normal communication systems (i.e. electronic data communication facilities, Control Telephony, etc).

In the event that the Balancing Mechanism has been suspended, it will not resume until the start of the Settlement Period determined by the BSC Panel in accordance with paragraph G3.1.2(d)(i) of the BSC.

For the avoidance of doubt, until resumption of the Balancing Mechanism, The Company is likely to continue to issue Emergency Instructions in accordance with BC2.9.

Users shall use reasonable endeavours to submit Physical notifications ten hours prior to the start of the Settlement Period determined by the BSC Panel in accordance with paragraph G3.1.2(d)(i) of the BSC and as notified by The Company to Users, in preparation for a return to normal operations.

In the event that the Balancing Mechanism has not been suspended and The Company has determined that the Total System has returned to normal operation, The Company shall inform Users and the BSCCo as soon as possible of the time and date at which (in The Company’s determination) the Total System returned to normal operation.

**Conclusion of Black Start**

**OC9.4.7.10**
The provisions of this OC9 shall cease to apply with effect from either:

(a) Where the Balancing Mechanism was suspended, the start of the Settlement Period that the Balancing Mechanism resumed normal operation, as determined by the BSC Panel and notified by the BSCCo in accordance with the provisions of
the BSC; or

(b) Where the Balancing Mechanism was not suspended, the end of the Settlement Period determined and notified by the BSCCo (in accordance with the provisions of the BSC) and corresponding to the time and date that The Company determined that the Total System had returned to normal operation.

Externally Interconnected System Operators

OC9.4.7.11 During a Black Start, The Company will, pursuant to the Interconnection Agreement with Externally Interconnected System Operators, agree with Externally Interconnected System Operators when their transmission systems can be Re-Synchronised to the Total System, if they have become separated.

OC9.4.7.12 Local Joint Restoration Plan Establishment

(a) In England and Wales, in relation to each Black Start Station and each Black Start HVDC System, The Company, NGET, the Network Operator and the relevant Black Start Service Provider will discuss and agree a Local Joint Restoration Plan. Where at the date of the first inclusion of this OC9.4.7.12 into the Grid Code a local plan covering the procedures to be covered in a Local Joint Restoration Plan is in existence and agreed, The Company will discuss this with NGET, the Network Operator and the relevant Generator or HVDC System Owner or DC Converter Station Owner to agree whether it is consistent with the principles set out in this OC9.4. If it is agreed to be so consistent, then it shall become a Local Joint Restoration Plan under this OC9 and the relevant provisions of OC9.4.7.12(b) shall apply. If it is not agreed to be so consistent, then the provisions of OC9.4.7.12(b) shall apply as if there is no Local Joint Restoration Plan in place.

In respect of Scottish Transmission Systems where a requirement for a Local Joint Restoration Plan is identified, The Company, the Relevant Scottish Transmission Licensee(s), the Network Operator and Black Start Service Provider’s) will discuss and agree a Local Joint Restoration Plan. In addition other Users, including other Generators or HVDC System Owners or DC Converter Station Owners, may be reasonably required by The Company to discuss and agree a Local Joint Restoration Plan.

(b) In England and Wales, where the need for a Local Joint Restoration Plan arises when there is none in place, the following provisions shall apply:

(i) The Company, NGET, the Network Operator and the relevant Black Start Service Provider will discuss and agree the detail of the Local Joint Restoration Plan as soon as the requirement for a Local Joint Restoration Plan is identified by The Company. The Company will notify all affected Users, and will initiate these discussions.

(ii) Each Local Joint Restoration Plan will be in relation to a specific Black Start Station or Black Start HVDC System.

(iii) The Local Joint Restoration Plan will record which Users and which User Sites are covered by the Local Joint Restoration Plan and set out what is required from The Company, NGET and each User should a Black Start situation arise.

(iv) Each Local Joint Restoration Plan shall be prepared by The Company to reflect the above discussions and agreement.
(v) Each page of the **Local Joint Restoration Plan** shall bear a date of issue and the issue number.

(vi) When a **Local Joint Restoration Plan** has been prepared, it shall be sent by The Company to NGET and the Users involved for confirmation of its accuracy.

(vii) The **Local Joint Restoration Plan** shall then (if its accuracy has been confirmed) be signed on behalf of The Company and on behalf of NGET and each relevant User by way of written confirmation of its accuracy.

(viii) Once agreed under this OC9.4.7.12, the procedure will become a **Local Joint Restoration Plan** under the **Grid Code** and (subject to any change pursuant to this OC9) will apply between The Company and NGET and the relevant Users as if it were part of the **Grid Code**.

(ix) Once signed, a copy of the **Local Joint Restoration Plan** will be distributed by The Company to NGET and each User which is a party to it accompanied by a note indicating the date of implementation.

(x) The Company, NGET and Users must make the **Local Joint Restoration Plan** readily available to the relevant operational staff.

(xi) If The Company, or NGET or any User which is a party to a **Local Joint Restoration Plan**, becomes aware that a change is needed to that **Local Joint Restoration Plan**, it shall (in the case of The Company) initiate a discussion between The Company and the relevant Users to seek to agree the relevant change. If NGET or a User becomes so aware, it shall contact The Company who will then initiate such discussions. The principles applying to establishing a new **Local Joint Restoration Plan** under this OC9.4.7.12 shall apply to such discussions and to any consequent changes.

(xii) The Company, NGET, the Network Operator, and the relevant Generator, or HVDC System Owner or DC Converter Station Owner will conduct regular joint exercises of the **Local Joint Restoration Plan** to which they are parties. The objectives of such exercises include:

- To test the effectiveness of the **Local Joint Restoration Plan**;
- To provide for joint training of the parties in respect of the **Local Joint Restoration Plan**;
- To maintain the parties’ awareness and familiarity of the **Local Joint Restoration Plan**;
- To promote understanding of each parties’ roles under a **Local Joint Restoration Plan**;
- To identify any improvement areas which should be incorporated in to the **Local Joint Restoration Plan**.
- The principles applying to the establishment of a new **Local Joint Restoration Plan** under this OC9.4.7.12 shall apply to any changes to the **Local Joint Restoration Plan**.

The Company will propose to the parties of a **Local Joint Restoration Plan** a date for the exercise to take place, to be agreed with the other parties. All the **Local Joint**
Restoration Plan parties will jointly share the task of planning, preparing, participating in and facilitating the exercises, which will normally be in desktop format or as otherwise agreed. The precise timing of the exercise for each Local Joint Restoration Plan will be agreed by all parties, but will not be less than one every 8 years.

(c) In respect of Scottish Transmission Systems, where the need for a Local Joint Restoration Plan arises, the following provisions shall apply:

(i) The Company, the Relevant Scottish Transmission Licensee(s), the Network Operator and the relevant Black Start Service Provider will discuss and agree the detail of the Local Joint Restoration Plan as soon as the requirement for a Local Joint Restoration Plan is identified by The Company. In addition, other Scottish Users, including other Generators, HVDC System Owners and DC Converter Station Owners, may be reasonably required by The Company to discuss and agree details of the Local Joint Restoration Plan as soon as the requirement for a Local Joint Restoration Plan is identified by The Company. The Company will notify the Relevant Scottish Transmission Licensee(s) and all affected Scottish Users, and will initiate these discussions.

(ii) Each Local Joint Restoration Plan may be in relation to either a specific Black Start Station or a number of Black Start Stations, and may include Gensets at Power Stations other than a Black Start Station. Each Local Joint Restoration Plan could equally apply to a specific Black Start HVDC System or a number of Black Start HVDC Systems and may include HVDC Systems or DC Converter Stations other than a Black Start HVDC System. For the avoidance of doubt, this would not preclude a Local Joint Restoration Plan from comprising a combination of Power Stations, HVDC Systems or DC Converter Stations irrespective of whether they have a Black Start Capability.

(iii) The Local Joint Restoration Plan will record which Scottish Users and which Scottish User Sites are covered by the Local Joint Restoration Plan and set out what is required from The Company, the Relevant Scottish Transmission Licensee(s) and each Scottish User should a Black Start situation arise.

(iv) Each Local Joint Restoration Plan shall be prepared by The Company to reflect the above discussions and agreement.

(v) Each page of the Local Joint Restoration Plan shall bear a date of issue and the issue number.

(vi) When a Local Joint Restoration Plan has been prepared, it shall be sent by The Company to the Relevant Scottish Transmission Licensee(s) and Scottish Users involved for confirmation of its accuracy.

(vii) The Local Joint Restoration Plan shall then (if its accuracy has been confirmed) be signed on behalf of The Company and on behalf of each relevant Scottish User and Relevant Scottish Transmission Licensee(s) by way of written confirmation of its accuracy.

(viii) Once agreed under this OC9.4.7.12, the procedure will become a Local Joint Restoration Plan under the Grid Code and (subject to any change pursuant to this OC9) will apply between The Company, Relevant Scottish Transmission Licensee(s) and the relevant Scottish Users as if it were part of the Grid Code.
Once signed, a copy of the Local Joint Restoration Plan will be distributed by The Company to the Relevant Scottish Transmission Licensee(s) and each Scottish User which is a party to it accompanied by a note indicating the date of implementation.

The Company, the Relevant Scottish Transmission Licensee(s) and Scottish Users must make the Local Joint Restoration Plan readily available to the relevant operational staff.

If The Company, the Relevant Scottish Transmission Licensee(s) or any Scottish User which is a party to a Local Joint Restoration Plan, becomes aware that a change is needed to that Local Joint Restoration Plan, it shall (in the case of The Company) initiate a discussion between The Company, the Relevant Scottish Transmission Licensee(s) and the relevant Scottish Users to seek to agree the relevant change. If a Scottish User or a Relevant Scottish Transmission Licensee becomes so aware, it shall contact The Company who will then initiate such discussions. The principles applying to establishing a new Local Joint Restoration Plan under this OC9.4.7.12 shall apply to such discussions and to any consequent changes.

The Company, the Relevant Scottish Transmission Licensee(s), the Network Operator and the relevant Black Start Service Provider will conduct regular joint exercises of the Local Joint Restoration Plan to which they are parties. The objectives of such exercises include:

- To test the effectiveness of the Local Joint Restoration Plan;
- To provide for joint training of the parties in respect of the Local Joint Restoration Plan;
- To maintain the parties’ awareness and familiarity of the Local Joint Restoration Plan;
- To promote understanding of each parties’ roles under a Local Joint Restoration Plan;
- To identify any improvement areas which should be incorporated into the Local Joint Restoration Plan.

The principles applying to the establishment of a new Local Joint Restoration Plan under this OC9.4.7.12 shall apply to any changes to the Local Joint Restoration Plan.

The Company will propose to the parties of a Local Joint Restoration Plan a date for the exercise to take place, to be agreed with the other parties. All the Local Joint Restoration Plan parties will jointly share the task of planning, preparing, participating in and facilitating the exercises, which will normally be in desktop format or as otherwise agreed. The precise timing of the exercise for each Local Joint Restoration Plan will be agreed by all parties, but will not be less than one every 8 years.

OC9.5 RE-SYNCHRONISATION OF DE-SYNCHRONISED ISLANDS
The provisions in this OC9.5 do not apply to the parts of the Total System that normally operate Out of Synchronism with the rest of the National Electricity Transmission System.

Further requirements, including the provision of information, applying to Re-synchronisation of De-synchronised Islands following any Total Shutdown or Partial Shutdown are detailed in OC9.5.6.

OC9.5.1
(a) Where parts of the Total System are Out of Synchronism with each other (each such part being termed a "De-Synchronised Island"), but there is no Total Shutdown or Partial Shutdown, The Company will instruct Users to regulate generation or Demand, as the case may be, to enable the De-Synchronised Islands to be Re-Synchronised and The Company will inform those Users when Re-Synchronisation has taken place.

(b) As part of that process, there may be a need to deal specifically with Embedded generation or storage in those De-Synchronised Islands. This OC9.5 provides for how such Embedded generation or storage should be dealt with. In Scotland, this OC9.5 also provides for how Transmission connected generation in De-Synchronised Islands should be dealt with.

(c) In accordance with the provisions of the BC, The Company may decide that, to enable Re-Synchronisation, it will issue Emergency Instructions in accordance with BC2.9 and it may be necessary to depart from normal Balancing Mechanism operation in accordance with BC2 in issuing Bid-Offer Acceptances.

(d) The provisions of this OC9.5 shall also apply during a Black Start to the Re-Synchronising parts of the System following a Total or Partial Shutdown, as indicated in OC9.4. In such cases, the provisions of the OC9.5 shall apply following completion and/or termination of the relevant Local Joint Restoration Plan(s) process as referred to in OC9.4.7.6(f).

OC9.5.2 Options

Generation in those De-Synchronised Islands may be dealt with in three different ways, more than one of which may be utilised in relation to any particular incident:-

OC9.5.2.1 Indirect Data

(a) The Company, each Generator with Synchronised (or connected and available to generate although not Synchronised) Genset(s) in the De-Synchronised Island and the Network Operator whose User System forms all or part of the De-Synchronised Island shall exchange information as set out in this OC9.5.2.1 to enable The Company to issue a Bid-Offer Acceptance or an Emergency Instruction to that Generator in relation to its Genset(s) in the De-Synchronised Island until Re-Synchronisation takes place, on the basis that it will (where practicable) seek to maintain the Target Frequency.

(b) The information to The Company from the Generator will cover its relevant operational parameters as outlined in the Balancing Codes (BC) and from The Company to the Generator will cover data on Demand and changes in Demand in the De-Synchronised Island.

(c) The information from the Network Operator to The Company will comprise data on Demand in the De-Synchronised Island, including data on any constraints within the De-Synchronised Island.
(d) The Company will keep the Network Operator informed of the Bid-Offer Acceptances or Emergency Instructions it is issuing to Embedded Genset(s) within the Network Operator’s User System forming part of the De-Synchronised Island.
OC9.5.2.2 Direct Data
(a) The Company will issue an Emergency Instruction and/or a Bid-Off er Acceptance, to the Generator to "float" local Demand and maintain Frequency at Target Frequency. Under this, the Generator will be required to regulate the output of its Genset(s) at the Power Station in question to the Demand prevailing in the De-Synchronised Island in which it is situated, until Re-Synchronisation takes place, on the basis that it will (where practicable) seek to maintain the Target Frequency.

(b) The Network Operator is required to be in contact with the Generator at the Power Station to supply data on Demand changes within the De-Synchronised Island.

(c) If more than one Genset is Synchronised on the De-Synchronised Island, or is connected to the De-Synchronised Island and available to generate although not Synchronised, the Network Operator will need to liaise with The Company to agree which Genset(s) will be utilised to accommodate changes in Demand in the De-Synchronised Island. The Network Operator will then maintain contact with the relevant Generator (or Generators) in relation to that Genset(s).

(d) The Generator at the Power Station must contact the Network Operator if the level of Demand which it has been asked to meet as a result of the Emergency Instruction and/or Bid-Off er Acceptance to "float" and the detail on Demand passed on by the Network Operator, is likely to cause problems for safety reasons (whether relating to personnel or Plant and/or Apparatus) in the operation of its Genset(s), in order that the Network Operator can alter the level of Demand which that Generator needs to meet. Any decision to operate outside any relevant parameters is one entirely for the Generator.

OC9.5.2.3 Control Features
(a) A system may be established in relation to a part of the National Electricity Transmission System and a Network Operator’s User System, if agreed between The Company and the Network Operator and any relevant Generator(s), whereby upon a defined fault(s) occurring, manual or automatic control features will operate to protect the National Electricity Transmission System and relevant Network Operator’s User System and Genset(s) and simplify the restoration of Demand in the De-Synchronised Island.

(b) In agreeing the establishment of such a system of control features, The Company will need to consider its impact on the operation of the National Electricity Transmission System.

OC9.5.2.4 Absence of Control Features System
If a system of control features under OC9.5.2.3 has not been agreed as part of an OC9 De-Synchronised Island Procedure under OC9.5.4 below, The Company may choose to utilise the procedures set out in OC9.5.2.1 or OC9.5.2.2, or may instruct the Genset(s) (or some of them) in the De-Synchronised Island to De-Synchronise.

OC9.5.3 Choice Of Option
In relation to each of the methods set out in OC9.5.2, where a De-Synchronised Island has come into existence and where an OC9 De-Synchronised Island Procedure under OC9.5.4 has been agreed, The Company, the Network Operator and relevant Generator(s) will operate in accordance with that OC9 De-Synchronised Islands Procedure unless The Company considers that the nature of the De-Synchronised Island situation is such that either:

(i) the OC9 De-Synchronised Island Procedure does not cover the situation; or
(ii) the provisions of the OC9 De-Synchronised Island Procedure are not appropriate,
in which case The Company will instruct the relevant Users and the Users will comply with The Company's instructions (which in the case of Generators will relate to generation and in the case of Network Operators will relate to Demand).
Agreeing Procedures

In relation to each relevant part of the Total System, The Company, the Network Operator and the relevant Generator will discuss and may agree a local procedure (an "OC9 De-Synchronised Island Procedure").

Where there is no relevant local procedure in place at 12th May 1997, or in the case where the need for an OC9 De-Synchronised Island Procedure arises for the first time, the following provisions shall apply:

(a) The Company, the Network Operator(s) and the relevant Generator(s) will discuss the need for, and the detail of, the OC9 De-Synchronised Island Procedure. As soon as the need for an OC9 De-Synchronised Island Procedure is identified by The Company or a User, and the party which identifies such a need will notify all affected Users (and The Company, if that party is a User), and The Company will initiate these discussions.

(b) Each OC9 De-Synchronised Island Procedure will be in relation to a specific Grid Supply Point, but if there is more than one Grid Supply Point between The Company and the Network Operator then the OC9 De-Synchronised Island Procedure may cover all relevant Grid Supply Points. In Scotland, the OC9 De-Synchronised Island Procedure may also cover parts of the National Electricity Transmission System connected to the User’s System(s) and Power Stations directly connected to the National Electricity Transmission System which are also likely to form part of the Power Island.

(c) The OC9 De-Synchronised Island Procedure will:

(i) record which Users and which User Sites are covered by the OC9 De-Synchronised Island Procedure;

(ii) record which of the three methods set out in OC9.5 (or combination of the three) shall apply, with any conditions as to applicability being set out as well;

(iii) set out what is required from The Company and each User should a De-Synchronised Island arise;

(iv) set out what action should be taken if the OC9 De-Synchronised Island Procedure does not cover a particular set of circumstances and will reflect that in the absence of any specified action, the provisions of OC9.5.3 will apply;

(v) in respect of Scottish Transmission Systems, the OC9 De-Synchronised Island Procedure may be produced with and include obligations on the Relevant Scottish Transmission Licensee(s); and

(vi) in respect of Scottish Transmission Systems, where the OC9 De-Synchronised Island Procedure includes the establishment of a De-synchronised Island, describe the route for establishment of the De-Synchronised Island.

(d) Each OC9 De-Synchronised Island Procedure shall be prepared by The Company to reflect the above discussions.

(e) Each page of the OC9 De-Synchronised Island Procedure shall bear a date of issue and the issue number.

(f) When an OC9 De-Synchronised Island Procedure is prepared, it shall be sent by The Company to the Users involved for confirmation of its accuracy.
(g) The **OC9 De-Synchronised Island Procedure** shall then be signed on behalf of The Company and on behalf of each relevant User by way of written confirmation of its accuracy.

(h) Once agreed under this OC9.5.4.1, the procedure will become an **OC9 De-Synchronised Island Procedure** under the Grid Code and (subject to any change pursuant to this OC9) will apply between The Company, Relevant Transmission Licensee and the relevant Users as if it were part of the Grid Code.

(i) Once signed, a copy will be distributed by The Company to each User which is a party accompanied by a note indicating the issue number and the date of implementation.

(j) The Company and Users must make the OC9 De-Synchronised Island Procedure readily available to the relevant operational staff.

(k) If a new User connects to the Total System and needs to be included with an existing **OC9 De-Synchronised Island Procedure**, The Company will initiate a discussion with that User and the Users which are parties to the relevant **OC9 De-Synchronised Island Procedure**. The principles applying to a new **OC9 De-Synchronised Island Procedure** under this OC9.5.4.1 shall apply to such discussions and to any consequent changes.

(l) If The Company, or any User which is a party to a **OC9 De-Synchronised Island Procedure**, becomes aware that a change is needed to that **OC9 De-Synchronised Island Procedure**, it shall (in the case of The Company) initiate a discussion between The Company and the relevant Users to seek to agree the relevant change. The principles applying to establishing a new **OC9 De-Synchronised Island Procedure** under this OC9.5.4.1 shall apply to such discussions and to any consequent changes. If a User becomes so aware, it shall contact The Company who will then initiate such discussions.

(m) If in relation to any discussions, agreement cannot be reached between The Company and the relevant Users, The Company will operate the System on the basis that it will discuss which of the three methods set out in OC9.5.2.1 to OC9.5.2.3 would be most appropriate at the time, if practicable. The complexities and uncertainties of recovery from a De-Synchronised Island means that The Company will decide, having discussed the situation with the relevant Users and taking into account the fact that the three methods may not cover the situation or be appropriate, the approach which is to be followed. The Company will instruct the relevant Users and the Users will comply with The Company’s instructions as provided in OC9.5.3.

OC9.5.4.2 Where there is a relevant local procedure in place at 12th May 1997, the following provisions shall apply:

(a) The Company and the Network Operator and the relevant Generator(s) will discuss the existing procedure to see whether it is consistent with the principles set out in this OC9.

(b) If it is, then it shall become an **OC9 De-Synchronised Island Procedure** under this **OC9**, and the relevant provisions of OC9.5.4.1 shall apply.
(c) If it is not, then the parties will discuss what changes are needed to ensure that it is consistent, and once agreed, the procedure will become an **OC9 De-Synchronised Island Procedure** under this **OC9**, and the relevant provisions of **OC9.5.4.1** shall apply.

(d) If agreement cannot be reached between **The Company** and the relevant **Users** after a reasonable period of time, the existing procedure will cease to apply and **The Company** will operate the **System** on the basis that it will discuss which of the three methods set out in **OC9.5.2.1** to **OC9.5.2.3** would be most appropriate at the time, if practicable. The complexities and uncertainties of recovery from a **De-Synchronised Island** means that **The Company** will decide, having discussed the situation with the relevant **Users** and taking into account the fact that the three methods may not cover the situation or be appropriate, the approach which is to be followed. **The Company** will instruct the relevant **Users** and the **Users** will comply with **The Company**’s instructions as provided in **OC9.5.3**.

**OC9.5.5** Where the **National Electricity Transmission System** is **Out of Synchronism** with the **Transmission System** of an **Externally Interconnected System Operator**, **The Company** will, pursuant to the **Interconnection Agreement** with that **Externally Interconnected System Operator**, agree with that **Externally Interconnected System Operator** when its **Transmission System** can be **Re-Synchronised** to the **National Electricity Transmission System**.

**OC9.5.6** Further requirements regarding **Re-synchronisation of De-synchronised Islands** following any **Total Shutdown** or **Partial Shutdown**

Following any **Total Shutdown** or **Partial Shutdown**, **The Company** expects that it will be necessary to interconnect **Power Islands** utilising the provisions of **OC9.5**. The complexities and uncertainties of recovery from a **Total Shutdown** or **Partial Shutdown** requires the provisions of **OC9.5** to be flexible, however, the strategies which **The Company** will, where practicable, be seeking to follow when **Re-synchronising De-synchronised Islands** following any **Total Shutdown** or **Partial Shutdown**, include the following:

(a) the provision of supplies to appropriate **Power Stations** to facilitate their synchronisation as soon as practicable;

(b) **energisation of a skeletal National Electricity Transmission System**;

(c) the **strategic restoration of Demand** in co-ordination with relevant **Network Operators**.

As highlighted in **OC9.4.3**, during a **Total Shutdown** or **Partial Shutdown** and during the subsequent recovery, which includes any period during which the procedures in this **OC9.5** apply, the **Licence Standards** may not apply and the **Total System** may be operated outside normal voltage and **Frequency** standards.

**OC9.5.7** To manage effectively and co-ordinate the restoration strategies of the **Total System** (any **Re-Synchronisation of De-Synchronised Islands**) following any **Total Shutdown** or **Partial Shutdown**, requires **The Company** and relevant **Users** to undertake certain planning activities as set out below:
(a) The Company and Network Operators shall review on a regular basis the processes by which each Power Island will be interconnected. This is likely to cover an exchange of information regarding the typical size, location and timing requirements for Demand to be reconnected and also include details (ability to change/disable) of the low frequency trip relay settings of the Demand identified.

(b) Each Generator shall provide to The Company information to assist The Company in the formulation of the restoration strategies of Power Island expansion. This information shall be provided in accordance with PC.A.5.7.

OC9.6 JOINT SYSTEM INCIDENT PROCEDURE

OC9.6.1 A "Joint System Incident" is

(a) an Event, wherever occurring (other than on an Embedded Small Power Station or Embedded Medium Power Station), which, in the opinion of The Company or a User, has or may have a serious and/or widespread effect.

(b) In the case of an Event on a User(s) System(s) (other than on an Embedded Small Power Station or Embedded Medium Power Station), the effect must be on the National Electricity Transmission System, and in the case of an Event on the National Electricity Transmission System, the effect must be on a User(s) System(s) (other than on an Embedded Small Power Station or Embedded Medium Power Station).

Where an Event on a User(s) System(s) has or may have no effect on the National Electricity Transmission System, then such an Event does not fall within OC9 and accordingly OC9 shall not apply to it.

OC9.6.2 (a) (i) Each User (other than Generators which only have Embedded Small Power Stations and/or Embedded Medium Power Stations) will provide in writing to The Company, and

(ii) The Company will provide in writing to each User (other than Generators which only have Embedded Small Power Stations and/or Embedded Medium Power Stations), a telephone number or numbers at which, or through which, senior management representatives nominated for this purpose and who are fully authorised to make binding decisions on behalf of The Company or the relevant User, as the case may be, can be contacted day or night when there is a Joint System Incident.

(b) The lists of telephone numbers will be provided in accordance with the timing requirements of the Bilateral Agreement and/or Construction Agreement with that User, prior to the time that a User connects to the National Electricity Transmission System and must be up-dated (in writing) as often as the information contained in them changes.

OC9.6.3 Following notification of an Event under OC7, The Company or a User, as the case may be, will, if it considers necessary, telephone the User or The Company, as the case may be, on the telephone number referred to in OC9.6.2, to obtain such additional information as it requires.

OC9.6.4 Following notification of an Event under OC7, and/or the receipt of any additional information requested pursuant to OC9.6.3, The Company or a User, as the case may be, will determine whether or not the Event is a Joint System Incident, and, if so, The Company and/or the User may set up an Incident Centre in order to avoid overloading the existing, operational/control arrangements be they The Company’s or User’s.
Where The Company has determined that an Event is a Joint System Incident, The Company shall, as soon as possible, notify all relevant Users that a Joint System Incident has occurred and, if appropriate, that it has established an Incident Centre and the telephone number(s) of its Incident Centre if different from those already supplied pursuant to OC9.6.2.

If a User establishes an Incident Centre it shall, as soon as possible, notify The Company that it has been established and the telephone number(s) of the Incident Centre if different from those already supplied pursuant to OC9.6.2.

The Company’s Incident Centre and/or the User’s Incident Centre will not assume any responsibility for the operation of the National Electricity Transmission System or User’s System, as the case may be, but will be the focal point in The Company or the User, as the case may be, for:

(a) the communication and dissemination of information between The Company and the senior management representatives of User(s); or
(b) between the User and the senior management representatives of The Company, as the case may be,

relating to the Joint System Incident. The term “Incident Centre” does not imply a specially built centre for dealing with Joint System Incidents, but is a communications focal point. During a Joint System Incident, the normal communication channels, for operational/control communication between The Company and Users will continue to be used.

All communications between the senior management representatives of the relevant parties with regard to The Company’s role in the Joint System Incident shall be made via The Company’s Incident Centre if it has been established.

All communications between the senior management representatives of The Company and a User with regard to that User’s role in the Joint System Incident shall be made via that User’s Incident Centre if it has been established.

The Company will decide when conditions no longer justify the need to use its Incident Centre and will inform all relevant Users of this decision.

Each User which has established an Incident Centre will decide when conditions no longer justify the need to use that Incident Centre and will inform The Company of this decision.

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(OC10)

EVENT INFORMATION SUPPLY

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OC10.1 INTRODUCTION

OC10.1.1. Operating Code No.10 ("OC10") sets out:

OC10.1.1.1 the requirements for the reporting in writing and, where appropriate, more fully, those Significant Incidents which were initially reported to The Company or a User orally under OC7; and

OC10.1.1.2 the mechanism for the joint investigation of a Significant Incident or a series of Significant Incidents if The Company and the relevant Users agree.

OC10.2 OBJECTIVE

The objective of OC10 is to facilitate the provision of more detailed information, in writing, of Significant Incidents which were initially orally reported under OC7 and to enable joint investigations to take place if The Company and the relevant Users agree.

OC10.3 SCOPE

OC10.3.1 OC10 applies to The Company and to Users, which in OC10 means:-

(a) Generators (other than those which only have Embedded Small Power Stations and/or Embedded Medium Power Stations);

(b) Network Operators;

(c) Non-Embedded Customers;

(d) DC Converter Station owners; and

(e) HVDC System Owners.

The procedure for Event information supply between The Company and Externally Interconnected System Operators is set out in the Interconnection Agreement with each Externally Interconnected System Operator.

OC10.4 PROCEDURE

OC10.4.1 Reporting

OC10.4.1.1 Written Reporting Of Events By Users To The Company

In the case of an Event which was initially reported by a User to The Company orally and subsequently determined by The Company to be a Significant Incident, and accordingly notified by The Company to a User pursuant to OC7, the User will give a written report to The Company, in accordance with OC10. The Company will not pass on this report to other affected Users but may use the information contained therein in preparing a report under OC10 to another User (or in a report which The Company is required to submit under an Interconnection Agreement) in relation to a Significant Incident (or its equivalent under an Interconnection Agreement or STC) on the National Electricity Transmission System which has been caused by (or exacerbated by) the Significant Incident on the User's System.

OC10.4.1.2 Written Reporting Of Events By The Company To Users

In the case of an Event which was initially reported by The Company to a User orally and subsequently determined by the User to be a Significant Incident, and accordingly notified by the User to The Company pursuant to OC7, The Company will give a written report to the User, in accordance with OC10. The User will not pass on the report to other affected Users but:
(a) a Network Operator may use the information contained therein in preparing a written report to a Generator with a Power Generating Module and/or Generating Unit and/or a Power Park Module connected to its System or to a DC Converter Station owner with a DC Converter connected to its System or to an HVDC System Owner with an HVDC System connected to its System or to another operator of a User System connected to its System in connection with reporting the equivalent of a Significant Incident under the Distribution Code (or other contract pursuant to which that Power Generating Module and/or Generating Unit and/or that Power Park Module or that DC Converter or that HVDC System or User System is connected to its System) (if the Significant Incident on the National Electricity Transmission System caused or exacerbated it); and

(b) a Generator may use the information contained therein in preparing a written report to another Generator with a Power Generating Module, Generating Unit or a Power Park Module connected to its System or to the operator of a User System connected to its System if it is required (by a contract pursuant to which that Power Generating Module and/or Generating Unit and/or a Power Park Module or that is connected to its System) to do so in connection with the equivalent of a Significant Incident on its System (if the Significant Incident on the National Electricity Transmission System caused or exacerbated it).

OC10.4.1.3 Form
A report under OC10.4.1 shall be sent to The Company or to a User, as the case may be, and will contain a confirmation of the oral notification given under OC7 together with more details relating to the Significant Incident although it (and any response to any question asked) need not state the cause of the Event save to the extent permitted under OC7.4.6.7 and OC7.4.6.9, and such further information which has become known relating to the Significant Incident since the oral notification under OC7. The report should, as a minimum, contain those matters specified in the Appendix to OC10. The Appendix is not intended to be exhaustive. The Company or the User, as the case may be, may raise questions to clarify the notification and the giver of the notification will, in so far as it is able, answer any questions raised.

OC10.4.1.4 Timing
A full written report under OC10.4.1 must, if possible, be received by The Company or the User, as the case may be, within 2 hours of The Company or the User, as the case may be, receiving oral notification under OC7. If this is not possible, the User or The Company, as the case may be, shall, within this period, submit a preliminary report setting out, as a minimum, those matters specified in the Appendix to OC10. As soon as reasonably practical thereafter, the User or The Company, as the case may be, shall submit a full written report containing the information set out in OC10.4.1.3.

OC10.4.2 Joint Investigations
OC10.4.2.1 Where a Significant Incident (or series of Significant Incidents) has been declared and a report (or reports) under OC10 submitted, The Company or a User which has either given or received a written report under OC10 may request that a joint investigation of a Significant Incident should take place.

OC10.4.2.2 Where there has been a series of Significant Incidents (that is to say, where a Significant Incident has caused or exacerbated another Significant Incident) the party requesting a joint investigation or the recipient of such a request, may request that the joint investigation should include an investigation into that other Significant Incident (or Significant Incidents).

OC10.4.2.3 The Company or a User may also request that:

(i) an Externally Interconnected System Operator and/or
(ii) Interconnector User or
(iii) (in the case of a Network Operator) a Generator with a Power Generating Module and/or a Generating Unit and/or a Power Park Module or a DC Converter Station owner with DC Converter connected to its System or an HVDC System Owner with a HVDC System connected to its System or another User System connected to its System or

(iv) (in the case of a Generator) another Generator with a Power Generating Module and/or a Generating Unit and/or a Power Park Module connected to its System or a User System connected to its System.

be included in the joint investigation.

OC10.4.2.4 A joint investigation will only take place if The Company and the User or Users involved agree to it (including agreement on the involvement of other parties referred to in OC10.4.2.3). The form and rules of, the procedure for, and all matters (including, if thought appropriate, provisions for costs and for a party to withdraw from the joint investigation once it has begun) relating to the joint investigation will be agreed at the time of a joint investigation and in the absence of agreement the joint investigation will not take place.

OC10.4.2.5 Requests relating to a proposed joint investigation will be in writing.

OC10.4.2.6 Any joint investigation under OC10 is separate to any investigation under the Disputes Resolution Procedure.
APPENDIX 1 - MATTERS TO BE INCLUDED IN A WRITTEN REPORT

MATTERS, IF APPLICABLE TO THE SIGNIFICANT INCIDENT AND TO THE RELEVANT USER (OR THE COMPANY, AS THE CASE MAY BE) TO BE INCLUDED IN A WRITTEN REPORT GIVEN IN ACCORDANCE WITH OC10.4.1 AND OC10.4.2

1. Time and date of Significant Incident.

2. Location.

3. Plant and/or Apparatus directly involved (and not merely affected by the Event).

4. Description of Significant Incident.

5. Demand (in MW) and/or generation (in MW) interrupted and duration of interruption.

6. Power Generating Module, Generating Unit, Power Park Module, HVDC System or DC Converter - Frequency response (MW correction achieved subsequent to the Significant Incident).

7. Power Generating Module, Generating Unit, Power Park Module, HVDC System or DC Converter - MVAr performance (change in output subsequent to the Significant Incident).

8. Estimated time and date of return to service.

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OC11.1 INTRODUCTION

OC11.1.1 Operating Code No.11 ("OC11") sets out the requirement that:
(a) Transmission HV Apparatus on Users’ Sites; and
(b) User HV Apparatus on Transmission Sites; and
(c) OTSDUW HV Apparatus on both Users’ Sites and the Transmission Sites;

shall have numbering and nomenclature in accordance with the system used from time to time by The Company.

OC11.1.2 The numbering and nomenclature (if required under the system of numbering and nomenclature used from time to time by The Company) of each item of HV Apparatus shall be included in the Operation Diagram prepared for each Transmission Site or User Site, as the case may be. Further provisions on Operation Diagrams are contained in the Connection Conditions or European Connection Conditions and in each Bilateral Agreement.

OC11.1.3 In OC11, the term "HV Apparatus" includes any SF6 Gas Zones associated with any HV Apparatus.

OC11.1.4 In OC11 the term "OTSDUW HV Apparatus" applies to any HV Apparatus installed by a User as OTSDUW until it is accepted on to the National Electricity Transmission System at which time for the purposes of OC11 it will be termed Transmission HV Apparatus.

OC11.2 OBJECTIVE

OC11.2.1 The overall objective of OC11 is to ensure, so far as possible, the safe and effective operation of the Total System and to reduce the risk of human error faults by requiring, in certain circumstances, that the numbering and nomenclature of Users’ HV Apparatus and OTSDUW HV Apparatus shall be in accordance with the system used from time to time by The Company.

OC11.3 SCOPE

OC11.3.1 OC11 applies to The Company and to Users, which in OC11 means:-
(a) Generators;
(b) Generators undertaking OTSDUW;
(c) Network Operators;
(d) Non-Embedded Customers;
(e) DC Converter Station owners; and
(f) HVDC System Owners

OC11.4 PROCEDURE

OC11.4.1.1 The term "User Site" means a site owned (or occupied pursuant to a lease, licence or other agreement) by a User in which there is a Connection Point (and in the case of OTSDUW, where there is a Connection Point or an Interface Point). For the avoidance of doubt, where a site is owned by a Relevant Transmission Licensee but occupied by a User (as aforesaid), the site is a User Site.

OC11.4.1.2 The term "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 (or in the case of OTSDUW, an Interface Point). For the avoidance of doubt, where a site is owned by a User but occupied by a Relevant Transmission Licensee (as aforesaid), the site is a Transmission Site.
OC11.4.2 Transmission HV Apparatus Or OTSDUW HV Apparatus On Users' Sites

(a) Transmission HV Apparatus or OTSDUW HV Apparatus on Users' Sites shall have numbering and nomenclature in accordance with the system used from time to time by The Company;

(b) when the Relevant Transmission Licensee is to install its HV Apparatus on a User's Site, The Company shall (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) notify the relevant User of the numbering and nomenclature to be adopted for that HV Apparatus at least eight months prior to proposed installation. When OTSDUW HV Apparatus is to be installed on a User's Site, The Company shall notify the relevant User of the numbering and nomenclature to be adopted for that OTSDUW HV Apparatus at least eight months prior to proposed installation;

(c) in the case of HV Apparatus, the notification will be made in writing to the relevant User and will consist of both a proposed Operation Diagram incorporating the proposed new Transmission HV Apparatus to be installed, its proposed numbering and nomenclature, and the date of its proposed installation. In the case of OTSDUW HV Apparatus, the notification will be provided as part of the OTSDUW Network Data and Information;

(d) the relevant User will respond in writing to The Company within one month of the receipt of the notification, confirming receipt and confirming either that any other HV Apparatus of the relevant User on such User Site does not have numbering and/or nomenclature which could be confused with that proposed by The Company, or, to the extent that it does, that the relevant other numbering and/or nomenclature will be changed before installation of the Transmission HV Apparatus or OTSDUW HV Apparatus;

(e) the relevant User will not install, or permit the installation of, any HV Apparatus, including OTSDUW HV Apparatus on such User Site which has numbering and/or nomenclature which could be confused with Transmission HV Apparatus which is either already on that User Site or which The Company has notified that User will be installed on that User Site.

OC11.4.3 User HV Apparatus Or OTSDUW HV Apparatus On Transmission Sites

(a) User HV Apparatus and any OTSDUW HV Apparatus on Transmission Sites shall have numbering and nomenclature in accordance with the system used from time to time by The Company;

(b) when a User is to install its HV Apparatus on an Transmission Site, or it wishes to replace existing HV Apparatus on a Transmission Site and it wishes to adopt new numbering and nomenclature for such HV Apparatus, the User shall (unless it gives rise to a Modification under the CUSC in which case the provisions of the CUSC as to the timing apply) notify The Company of the details of the HV Apparatus and the proposed numbering and nomenclature to be adopted for that HV Apparatus, at least eight months prior to proposed installation;

(c) the notification will be made in writing to The Company and shall consist of both a proposed Operation Diagram incorporating the proposed new HV Apparatus of the User to be installed, its proposed numbering and nomenclature, and the date of its proposed installation;

(d) The Company will respond in writing to the User within one month of the receipt of the notification stating whether or not The Company accepts the User's proposed numbering and nomenclature and, if they are not acceptable, it shall give details of the numbering and nomenclature which the User shall adopt for that HV Apparatus;

(e) when a User is to install OTSDUW HV Apparatus on a Transmission Site, The Company shall notify the relevant User of the numbering and nomenclature to be adopted for that HV Apparatus at least eight months prior to proposed installation. This notification will be provided as part of the OTSDUW Network Data and Information.

OC11.4.4 Changes

Issue 6 Revision 0
Where The Company in its reasonable opinion has decided that it needs to change the existing numbering or nomenclature of Transmission HV Apparatus on a User’s Site or of Users’ HV Apparatus on a Transmission Site:

(a) the provisions of paragraph OC11.4.2 shall apply to such change of numbering or nomenclature of Transmission HV Apparatus with any necessary amendments to those provisions to reflect that only a change is being made; and

(b) in the case of a change in the numbering or nomenclature of Users’ HV Apparatus on a Transmission Site, The Company will (unless it gives rise to a Modification under the CUSC, in which case the provisions of the CUSC as to the timing apply) notify the User of the numbering and/or nomenclature the User shall adopt for that HV Apparatus (the notification to be in a form similar to that envisaged under OC11.4.2) at least eight months prior to the change being needed and the User will respond in writing to The Company within one month of the receipt of the notification, confirming receipt.

In either case the notification shall indicate the reason for the proposed change.

OC11.4.5 Users will be provided upon request with details of The Company’s then current numbering and nomenclature system in order to assist them in planning the numbering and nomenclature for their HV Apparatus or OTSDUW HV Apparatus on Transmission Sites and OTSDUW HV Apparatus on Users’ Sites.

OC11.4.6 When a User installs HV Apparatus or OTSDUW HV Apparatus which is the subject of OC11, the User shall be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature. Where a User is required by OC11 to change the numbering and/or nomenclature of HV Apparatus which is the subject of OC11, the User will be responsible for the provision and erection of clear and unambiguous labelling by the required date.

When a Relevant Transmission Licensee installs HV Apparatus which is the subject of OC11, The Company shall be responsible for the provision and erection of a clear and unambiguous labelling showing the numbering and nomenclature. Where The Company in coordination with the Relevant Transmission Licensee changes the numbering and/or nomenclature of HV Apparatus which is the subject of OC11, The Company in coordination with the Relevant Transmission Licensee will be responsible for the provision and erection of clear and unambiguous labelling showing the numbering and nomenclature by the required date.

OC11.4.7 For sites in England and Wales, The Company will not change its system of numbering and nomenclature in use immediately prior to the Transfer Date (which is embodied in OM5 (Operation Memorandum No.5 - Numbering and Nomenclature of HV Apparatus on the CEBG Grid System Issue 3 June 1987)), other than to reflect new or newly adopted technology or HV Apparatus. For the avoidance of doubt, this OC11.4.7 refers to the system of numbering and nomenclature, and does not preclude changes to the numbering and/or nomenclature of HV Apparatus which are necessary to reflect newly installed HV Apparatus, or re-configuration of HV Apparatus installed, and similar changes being made in accordance with that system of numbering and nomenclature.

< END OF OPERATING CODE NO. 11 >
# OPERATING CODE NO. 12
## OC12
### SYSTEM TESTS
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OC12.1 INTRODUCTION

OC12.1.1 Operating Code No.12 ("OC12") relates to System Tests, which are 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.

OC12.1.2 OC12 deals with the responsibilities and procedures for arranging and carrying out System Tests which have (or may have) an effect on the Systems of The Company and Users and/or on the System of any Externally Interconnected System Operator. Where a System Test proposed by a User will have no effect on the National Electricity Transmission System, then such a System Test does not fall within OC12 and accordingly OC12 shall not apply to it. A System Test proposed by The Company which will have an effect on the System of a User will always fall within OC12.

OC12.2 OBJECTIVE

The overall objectives of OC12 are:

OC12.2.1 to ensure, so far as possible, that System Tests proposed to be carried out either by:

(a) a User (or certain persons in respect of Systems Embedded within a Network Operator’s System) which may have an effect on the Total System or any part of the Total System (in addition to that User’s System) including the National Electricity Transmission System; or

(b) by The Company which may have an effect on the Total System or any part of the Total System (in addition to the National Electricity Transmission System)

do not threaten the safety of either their personnel or the general public, cause minimum threat to the security of supplies and to the integrity of Plant and/or Apparatus, and cause minimum detriment to The Company and Users;

OC12.2.2 to set out the procedures to be followed for establishing and reporting System Tests.

OC12.3 SCOPE

OC12 applies to The Company and to Users, which in OC12 means:-

(a) Generators other than in respect of Embedded Medium Power Stations and Embedded Small Power Stations (and the term Generator in OC12 shall be constructed accordingly);

(b) Network Operators;

(c) Non-Embedded Customers; and

(d) DC Converter Station owners other than in respect of Embedded DC Converter Stations.

(e) HVDC System Owners other than in respect of Embedded HVDC Systems.

The procedure for the establishment of System Tests on the National Electricity Transmission System, with Externally Interconnected System Operators which do not affect any User, is set out in the Interconnection Agreement with each Externally Interconnected System Operator. The position of Externally Interconnected System Operators and Interconnector Users is also referred to in OC12.4.2.

OC12.3.2 Each Network Operator will liaise within The Company as necessary in those instances where an Embedded Person intends to perform a System Test which may have an effect on the Total System or any part of the Total System (in addition to that Generator’s or other User’s System) including the National Electricity Transmission System. The Company is not required to deal with such persons.

OC12.3.3 Each Network Operator shall be responsible for co-ordinating with the Embedded Person or such other person and assessing the effect of any System Tests upon:
(a) any **Embedded Medium Power Station**, **Embedded Small Power Stations**, **Embedded HVDC System** or **Embedded DC Converter Station** within the **Network Operator’s System**; or

(b) any other **User** connected to or within the **Network Operator’s System**.

The **Company** is not required to deal with such persons.

---

**OC12.4**

**PROCEDURE**

**OC12.4.1** **Proposal Notice**

**OC12.4.1.1** Where a **User** (or in the case of a **Network Operator**, a person in respect of **Systems Embedded** within its **System**, as the case may be) has decided that it would like to undertake a **System Test** it shall submit a notice (a “Proposal Notice”) to the **Company** at least twelve months in advance of the date it would like to undertake the proposed **System Test**.

**OC12.4.1.2** The **Proposal Notice** shall be in writing and shall contain details of the nature and purpose of the proposed **System Test** and shall indicate the extent and situation of the **Plant** and/or **Apparatus** involved.

**OC12.4.1.3** If the **Company** is of the view that the information set out in the **Proposal Notice** is insufficient, it will contact the person who submitted the **Proposal Notice** (the “**Test Proposer**”) as soon as reasonably practicable, with a written request for further information. The **Company** will not be required to do anything under **OC12** until it is satisfied with the details supplied in the **Proposal Notice** or pursuant to a request for further information.

**OC12.4.1.4** If the **Company** wishes to undertake a **System Test**, the **Company** shall be deemed to have received a **Proposal Notice** on that **System Test**.

**OC12.4.1.5** Where, under **OC12**, the **Company** is obliged to notify or contact the **Test Proposer**, the **Company** will not be so obliged where it is the **Company** that has proposed the **System Test**. **Users** and the **Test Panel**, where they are obliged under **OC12** to notify, send reports to or otherwise contact both the **Company** and the **Test Proposer**, need only do so once where the **Company** is the proposer of the **System Test**.

**OC12.4.2** **Preliminary Notice And Establishment Of Test Panel**

**OC12.4.2.1** Using the information supplied to it under **OC12.4.1** the **Company** will determine, in its reasonable estimation, which **Users**, other than the **Test Proposer**, may be affected by the proposed **System Test**. If the **Company** determines, in its reasonable estimation, that an **Externally Interconnected System Operator** and/or **Interconnector User** (or **Externally Interconnected System Operators** and/or **Interconnector Users**) may be affected by the proposed **System Test**, then (provided that the **Externally Interconnected System Operator** and/or **Interconnector User** (or each **Externally Interconnected System Operator** and/or **Interconnector User** where there is more than one affected) undertakes to all the parties to the **Grid Code** to be bound by the provisions of the **Grid Code** for the purposes of the **System Test**) for the purposes of the remaining provisions of this **OC12**, that **Externally Interconnected System Operator** and/or **Interconnector User** (or each of those **Externally Interconnected System Operators** and/or **Interconnector Users**) will be deemed to be a **User** and references to the **Total System** or to the **Plant** and/or **Apparatus** of a **User** will be deemed to include a reference to the **Transmission** or distribution **System** and **Plant** and/or **Apparatus** of that **Externally Interconnected System Operator** and/or **Interconnector User** or (as the case may be) those **Externally Interconnected System Operators** and/or **Interconnector Users**. In the event that the **Externally Interconnected System Operator** and/or **Interconnector User** (or any of the **Externally Interconnected System Operators** and/or **Interconnector Users** where there is more than one affected) refuses to so undertake, then the **System Test** will not take place.

**OC12.4.2.2** The **Company** will appoint a person to co-ordinate the **System Test** (a “**Test Co-ordinator**”) as soon as reasonably practicable after it has, or is deemed to have, received a **Proposal Notice** and in any event prior to the distribution of the **Preliminary Notice** referred to below. The **Test Co-ordinator** shall act as Chairperson of the **Test Panel** and shall be an ex-officio member of the **Test Panel**.
(a) Where The Company decides, in its reasonable opinion, that the National Electricity Transmission System will or may be significantly affected by the proposed System Test, then the Test Co-ordinator will be a suitably qualified person nominated by The Company after consultation with the Test Proposer and the Users identified under OC12.4.2.1.

(b) Where The Company decides, in its reasonable opinion, that the National Electricity Transmission System will not be significantly affected by the proposed System Test, then the Test Co-ordinator will be a suitably qualified person nominated by the Test Proposer after consultation with the Company.

(c) The Company will, as soon as reasonably practicable after it has received, or is deemed to have received, a Proposal Notice, contact the Test Proposer where the Test Co-ordinator is to be a person nominated by the Test Proposer and invite it to nominate a person as Test Co-ordinator. If the Test Proposer is unable or unwilling to nominate a person within seven days of being contacted by The Company then the proposed System Test will not take place.

OC12.4.2.3 The Company will notify all Users identified by it under OC12.4.2.1 of the proposed System Test by a notice in writing (a "Preliminary Notice") and will send a Preliminary Notice to the Test Proposer. The Preliminary Notice will contain:

(a) the details of the nature and purpose of the proposed System Test, the extent and situation of the Plant and/or Apparatus involved and the identity of the Users identified by The Company under OC12.4.2.1 and the identity of the Test Proposer;

(b) an invitation to nominate within one month a suitably qualified representative (or representatives, if the Test Co-ordinator informs The Company that it is appropriate for a particular User including the Test Proposer) to be a member of the Test Panel for the proposed System Test;

(c) the name of the The Company representative (or representatives) on the Test Panel for the proposed System Test; and

(d) the name of the Test Co-ordinator and whether they were nominated by the Test Proposer or by The Company.

OC12.4.2.4 The Preliminary Notice will be sent within one month of the later of either the receipt by The Company of the Proposal Notice, or of the receipt of any further information requested by The Company under OC12.4.1.3. Where The Company is the proposer of the System Test, the Preliminary Notice will be sent within one month of the proposed System Test being formulated.

OC12.4.2.5 Replies to the invitation in the Preliminary Notice to nominate a representative to be a member of the Test Panel must be received by The Company within one month of the date on which the Preliminary Notice was sent to the User by The Company. Any User which has not replied within that period will not be entitled to be represented on the Test Panel. If the Test Proposer does not reply within that period, the proposed System Test will not take place and The Company will notify all Users identified by it under OC12.4.2.1 accordingly.

OC12.4.2.6 The Company will, as soon as possible after the expiry of that one month period, appoint the nominated persons to the Test Panel and notify all Users identified by it under OC12.4.2.1 and the Test Proposer of the composition of the Test Panel.

OC12.4.3 Test Panel

OC12.4.3.1 A meeting of the Test Panel will take place as soon as possible after The Company has notified all Users identified by it under OC12.4.2.1 and the Test Proposer of the composition of the Test Panel, and in any event within one month of the appointment of the Test Panel.

OC12.4.3.2 The Test Panel shall consider:

(a) the details of the nature and purpose of the proposed System Test and other matters set out in the Proposal Notice (together with any further information requested by The Company under OC12.4.1.3);

(b) the economic, operational and risk implications of the proposed System Test;
(c) the possibility of combining the proposed System Test with any other tests and with Plant and/or Apparatus outages which arise pursuant to the Operational Planning requirements of The Company and Users; and

(d) implications of the proposed System Test on the operation of the Balancing Mechanism, in so far as it is able to do so.

OC12.4.3.3 Users identified by The Company under OC12.4.2.1, the Test Proposer and The Company (whether or not they are represented on the Test Panel) shall be obliged to supply that Test Panel, upon written request, with such details as the Test Panel reasonably requires in order to consider the proposed System Test.

OC12.4.3.4 The Test Panel shall be convened by the Test Co-ordinator as often as they deem necessary to conduct its business.

OC12.4.4 Proposal Report

OC12.4.4.1 Within two months of first meeting, the Test Panel will submit a report (a "Proposal Report"), which will contain:

(a) proposals for carrying out the 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 Proposal Report may include requirements for indemnities (including an indemnity from the relevant Network Operator to The Company and other Users in relation to its Embedded Persons) to be given in respect of claims and losses arising from the System Test. All System Test procedures must comply with all applicable legislation.

OC12.4.4.2 If the Test Panel is unable to agree unanimously on any decision in preparing its Proposal Report, the proposed System Test will not take place and the Test Panel will be dissolved.

OC12.4.4.3 The Proposal Report will be submitted to The Company, the Test Proposer and to each User identified by The Company under OC12.4.2.1.

OC12.4.4.4 Each recipient will respond to the Test Co-ordinator with its approval of the Proposal Report or its reason for non-approval within fourteen days of receipt of the Proposal Report. If any recipient does not respond, the System Test will not take place and the Test Panel will be dissolved.

OC12.4.4.5 In the event of non-approval by one or more recipients, the Test Panel will meet as soon as practicable in order to determine whether the proposed System Test can be modified to meet the objection or objections.

OC12.4.4.6 If the proposed System Test cannot be so modified, the System Test will not take place and the Test Panel will be dissolved.

OC12.4.4.7 If the proposed System Test can be so modified, the Test Panel will, as soon as practicable, and in any event within one month of meeting to discuss the responses to the Proposal Report, submit a revised Proposal Report and the provisions of OC12.4.4.3 and OC12.4.4.4 will apply to that submission.

OC12.4.4.8 In the event of non-approval of the revised Proposal Report by one or more recipients, the System Test will not take place and the Test Panel will be dissolved.
OC12.4.5 Test Programme

OC12.4.5.1 If the Proposal Report (or, as the case may be, the revised Proposal Report) is approved by all recipients, the proposed System Test can proceed and at least one month prior to the date of the proposed System Test, the Test Panel will submit to The Company, the Test Proposer and each User identified by The Company under OC12.4.2.1, a programme (the "Test Programme") stating 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 site safety) and such other matters as the Test Panel deems appropriate.

OC12.4.5.2 The Test Programme will, subject to OC12.4.5.3, bind all recipients to act in accordance with the provisions of the Test Programme in relation to the proposed System Test.

OC12.4.5.3 Any problems with the proposed System Test which arise or are anticipated after the issue of the Test Programme and prior to the day of the proposed System Test, must be notified to the Test Co-ordinator as soon as possible in writing. If the Test Co-ordinator decides that these anticipated problems merit an amendment to, or postponement of, the System Test, they shall notify the Test Proposer (if the Test Co-ordinator was not appointed by the Test Proposer), The Company and each User identified by The Company under OC12.4.2.1 accordingly.

OC12.4.5.4 If on the day of the proposed System Test, operating conditions on the Total System are such that any party involved in the proposed System Test wishes to delay or cancel the start or continuance of the System Test, they shall immediately inform the Test Co-ordinator of this decision and the reasons for it. The Test Co-ordinator shall then postpone or cancel, as the case may be, the System Test and shall, if possible, agree with the Test Proposer (if the Test Co-ordinator was not appointed by the Test Proposer), The Company and all Users identified by The Company under OC12.4.2.1 another suitable time and date. If they cannot reach such agreement, the Test Co-ordinator shall reconvene the Test Panel as soon as practicable, which will endeavour to arrange another suitable time and date for the System Test, in which case the relevant provisions of OC12 shall apply.

OC12.4.6 Final Report

OC12.4.6.1 At the conclusion of the System Test, the Test Proposer shall be responsible for preparing a written report on the System Test (the "Final Report") for submission to The Company and other members of the Test Panel. The Final Report shall be submitted within three months of the conclusion of the System Test unless a different period has been agreed by the Test Panel prior to the System Test taking place.

OC12.4.6.2 The Final Report shall not be submitted to any person who is not a member of the Test Panel unless the Test Panel, having considered the confidentiality issues arising, shall have unanimously approved such submission.

OC12.4.6.3 The Final Report shall include a description of the Plant and/or Apparatus tested and a description of the System Test carried out, together with the results, conclusions and recommendations.

OC12.4.6.4 When the Final Report has been prepared and submitted in accordance with OC12.4.6.1, the Test Panel will be dissolved.

OC12.4.7 Timetable Reduction

OC12.4.7.1 In certain cases a System Test may be needed on giving less than twelve months notice. In that case, after consultation with the Test Proposer and User(s) identified by The Company under OC12.4.2.1, The Company shall draw up a timetable for the proposed System Test and the procedure set out in OC12.4.2 to OC12.4.6 shall be followed in accordance with that timetable.

< END OF OPERATING CODE NO. 12 >
# Balancing Code No. 1 (BC1)

**Pre Gate Closure Process**

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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, then this will be treated as a National Electricity Transmission System Warning as defined in OC7.4.8. 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. In this case The Company will also endeavor, where time allows, to issue a National Electricity Transmission System Warning – High Risk of Embedded Generation Reduction and/or a National Electricity Transmission System Warning Embedded Generation Control Imminent as applicable.

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.

<table>
<thead>
<tr>
<th>Data Name</th>
<th>BMU name</th>
<th>Time From</th>
<th>From level (MW)</th>
<th>Time To</th>
<th>To level (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>PN , TAGENT , BMUNIT01</td>
<td>2001-11-03 06:30</td>
<td>77</td>
<td>2001-11-03 07:00</td>
<td>100</td>
<td></td>
</tr>
<tr>
<td>PN , TAGENT , BMUNIT01</td>
<td>2001-11-03 07:00</td>
<td>100</td>
<td>2001-11-03 07:12</td>
<td>150</td>
<td></td>
</tr>
<tr>
<td>PN , TAGENT , BMUNIT01</td>
<td>2001-11-03 07:12</td>
<td>150</td>
<td>2001-11-03 07:30</td>
<td>175</td>
<td></td>
</tr>
</tbody>
</table>

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.

<table>
<thead>
<tr>
<th>Data Name</th>
<th>BMU name</th>
<th>Time From</th>
<th>From level (MW)</th>
<th>Time To</th>
<th>To level (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MEL</td>
<td>TAGENT</td>
<td>BMUNIT01</td>
<td>2001-11-03 05:00</td>
<td>410</td>
<td>2001-11-03 09:35</td>
</tr>
<tr>
<td>MEL</td>
<td>TAGENT</td>
<td>BMUNIT01</td>
<td>2001-11-03 09:35</td>
<td>450</td>
<td>2001-11-03 12:45</td>
</tr>
<tr>
<td>MIL</td>
<td>TAGENT</td>
<td>BMUNIT04</td>
<td>2001-11-03 06:30</td>
<td>-200</td>
<td>2001-11-03 07:00</td>
</tr>
</tbody>
</table>
**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.

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

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

![Graphical illustration of Bid-Offer data](image)
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

**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.1.6.1 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

<table>
<thead>
<tr>
<th>CCGT MODULE ACTIVE POWER MW</th>
<th>CCGT GENERATING UNITS* AVAILABLE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1st GT</td>
</tr>
<tr>
<td>0MW to 150MW</td>
<td>/</td>
</tr>
<tr>
<td>151MW to 250MW</td>
<td>/</td>
</tr>
<tr>
<td>251MW to 300MW</td>
<td>/</td>
</tr>
<tr>
<td>301MW to 400MW</td>
<td>/</td>
</tr>
<tr>
<td>401MW to 450MW</td>
<td>/</td>
</tr>
<tr>
<td>451MW to 550MW</td>
<td>/</td>
</tr>
</tbody>
</table>

* 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:

<table>
<thead>
<tr>
<th>Plant</th>
<th>Synchronises when offer is greater than MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generating 1</td>
<td>......MW</td>
</tr>
<tr>
<td>Generating 2</td>
<td>......MW</td>
</tr>
<tr>
<td>Generating 3</td>
<td>......MW</td>
</tr>
<tr>
<td>Generating 4</td>
<td>......MW</td>
</tr>
<tr>
<td>Generating 5</td>
<td>......MW</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>BM Unit Name</th>
<th>Power Park Module [unique identifier]</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>POWER PARK UNIT AVAILABILITY</td>
</tr>
<tr>
<td></td>
<td>Description (Make/Model)</td>
</tr>
<tr>
<td></td>
<td>Number of units</td>
</tr>
<tr>
<td></td>
<td>POWER PARK UNIT AVAILABILITY</td>
</tr>
<tr>
<td></td>
<td>Description (Make/Model)</td>
</tr>
<tr>
<td></td>
<td>Number of units</td>
</tr>
</tbody>
</table>

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

<table>
<thead>
<tr>
<th>MW</th>
<th>ACTIVE POWER OUTPUT</th>
</tr>
</thead>
<tbody>
<tr>
<td>0MW to 150MW</td>
<td>150 150 150 100</td>
</tr>
<tr>
<td>151MW to 250MW</td>
<td>/</td>
</tr>
<tr>
<td>251MW to 300MW</td>
<td>/ /</td>
</tr>
<tr>
<td>301MW to 400MW</td>
<td>/ /</td>
</tr>
<tr>
<td>401MW to 450MW</td>
<td>/ / /</td>
</tr>
<tr>
<td>451MW to 550MW</td>
<td>/ / /</td>
</tr>
</tbody>
</table>

* 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, 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;
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.

**Aggregator Impact Matrix**

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.

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**

<table>
<thead>
<tr>
<th>BMU Name</th>
<th>Operational Day from which values apply</th>
<th>Grid Supply Point</th>
<th>% Impact</th>
<th>Grid Supply Point</th>
<th>% Impact</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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:

<table>
<thead>
<tr>
<th>Target Data Release Time</th>
<th>Period Start Time</th>
<th>Period End Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>02:00</td>
<td>02:00 D0</td>
<td>05:00 D+1</td>
</tr>
<tr>
<td>10:00</td>
<td>10:00 D0</td>
<td>05:00 D+1</td>
</tr>
<tr>
<td>16:00</td>
<td>05:00 D+1</td>
<td>05:00 D+2</td>
</tr>
<tr>
<td>16:30</td>
<td>16:30 D0</td>
<td>05:00 D+1</td>
</tr>
<tr>
<td>22:00</td>
<td>22:00 D0</td>
<td>05:00 D+2</td>
</tr>
</tbody>
</table>

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**

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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 Intertipping 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 User (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 Intertipping 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.
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.

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 output 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.

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 (or User System Entry Point if Embedded) 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 **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**.

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**BC2.6.2 Communication With Control Points In Emergency Circumstances**

**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 Communication With Network Operators In Emergency Circumstances**

**The Company** will issue **Emergency Instructions** direct to the **Network Operator** at each **Control Centre** in relation to actions including special actions as set out in BC1.7, actions in the categories set out under BC2.9.3.3. **Embedded Generation Control** and **Demand Control actions. 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; **OC6B** contains further provisions relating to **Embedded Generation Control** instructions.

**BC2.6.4 Communication with Externally Interconnected System Operators in Emergency Circumstances**

**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 Communications during Planned Outages of Electronic Data Communication Facilities**

**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.

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**BC2.7**

**BID-OFFER ACCEPTANCES**

**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, 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 BC1 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; or

(f) the need to implement Embedded Generation Control in accordance with OC6B.

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’.

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**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 Agreement**, 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 case 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.
(f) a requirement for Embedded Generation Control or restoration pursuant to OC6B

BC2.9.4 Maintaining Adequate System And Localised NRAPM (Negative Reserve Active Power Margin)

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). If The Company is still unable to satisfy the required System NRAPM or Localised NRAPM then The Company may issue Emergency Instructions to Network Operator(s) as set out under OC6B to carry out Embedded Generation Control.

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.
BC2.9.6 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.

BC2.9.7 When instructing exporting BM Units which form part of an On-Site Generator Site to reduce generation or export under this BC2.9.4, The Company will not issue an instruction which would reduce generation or export 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 Maintaining an adequate level of Frequency Sensitive Generation

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 results 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) (i) BM Participants, not subject to the provisions of BC2.9.7.2(b)(ii), should operate in relation to any period of time in accordance with the last Physical Notification prevailing at Gate Closure received prior to 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;

(ii) BM Participants, who are not required to have Control Telephony or System Telephony staffed at all times as provided for in CC7.9 or ECC7.9, should during periods when their telephones are not staffed operate in relation to any period of time in accordance with the last Physical Notification prevailing at Gate Closure received at the prior 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. If the BM Participants automatic equipment identifies there has been a computer system failure then 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. For the avoidance of doubt between 08:00 and 18:00 hours the provisions of BC2.9.7.2(b)(ii) shall apply.

(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.

BC2.9.8 Market Suspension

BC2.9.8.1 Within the GB Synchronous Area, the National Electricity Transmission System shall be determined to be in an emergency state when operational security analysis indicates one or more of the following situations occurring:

   a) A situation where there is (or could be) a violation of one or more operational criteria as defined under the Security and Quality of Supply Standard (SQSS); or

   b) A situation when Unacceptable Frequency Conditions as defined under the System Security and Quality of Supply Standard (SQSS) have occurred; or

   c) At least one measure of the System Defence Plan is activated; or

   d) There is a failure of the computing facilities used to control and operate the National Electricity Transmission System or unplanned outages of Electronic Communication and Computing Facilities as provided for in BC2.9.7 or the loss of communication, computing and data facilities with other Transmission Licensees as provided for in STCP 06-4.

BC2.9.8.2 While the National Electricity Transmission System is in an emergency state if, after issuing National Electricity Transmission System Warnings and Emergency Instructions in accordance with (but not limited to) the requirements under OC7.4 and BC2.9, the situation deteriorates to such an extent that it results in:-

   a) a Total Shutdown, The Company will suspend the market in accordance with the provisions of OC9.4.6; or

   b) a Partial Shutdown, The Company will suspend the market but only where the Market Suspension Threshold has been met in accordance with OC9.4.6.

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 or ECC.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).
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.

LIAISON WITH EXTERNALLY INTERCONNECTED SYSTEM OPERATORS

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.

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

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.

For each BM Unit the Bid-Offer Acceptance will consist of a series of MW figures and associated times.
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.

Bid-Offer Acceptances Given By Automatic Logging Device

(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.

Bid-Offer Acceptances Given By Telephone

(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 or ECC.8, System Ancillary Services consist of Part 1 and Part 2 System Ancillary Services.

Part 1 System Ancillary Services Comprise:

(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.

Part 2 System Ancillary Services Comprise:

(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 Instructions Given By Automatic Logging Device

(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
(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.”
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:

<table>
<thead>
<tr>
<th>Instruction Name</th>
<th>Description</th>
<th>Type of Instruction</th>
</tr>
</thead>
<tbody>
<tr>
<td>MVAr Output</td>
<td>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.</td>
<td>MVAr</td>
</tr>
</tbody>
</table>
## 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.

<table>
<thead>
<tr>
<th>Instruction Name</th>
<th>Description</th>
<th>Type of Instruction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Target Voltage Levels</td>
<td>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.</td>
<td>VOLT</td>
</tr>
</tbody>
</table>

## 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.

<table>
<thead>
<tr>
<th>Instruction Name</th>
<th>Description</th>
<th>Type of Instruction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Setpoint Voltage</td>
<td>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).</td>
<td>SETPOINT</td>
</tr>
<tr>
<td>Instruction Name</td>
<td>Description</td>
<td>Type of Instruction</td>
</tr>
<tr>
<td>------------------</td>
<td>-------------</td>
<td>---------------------</td>
</tr>
<tr>
<td>Slope</td>
<td>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.</td>
<td>SLOPE</td>
</tr>
<tr>
<td>Tap Changes</td>
<td>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.</td>
<td>TAPP</td>
</tr>
<tr>
<td>Maximum MVAr Output (&quot;maximum excitation&quot;)</td>
<td>Under certain conditions, such as low System voltage, an instruction to maximum MVAr output at instructed MW output (&quot;maximum excitation&quot;) 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).</td>
<td></td>
</tr>
<tr>
<td>Maximum MVAr Absorption (&quot;minimum excitation&quot;)</td>
<td>Under certain conditions, such as high System voltage, an instruction to maximum MVAr absorption at instructed MW output (&quot;minimum excitation&quot;) 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).</td>
<td></td>
</tr>
</tbody>
</table>

**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 as 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.
Company name REVISID 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

<table>
<thead>
<tr>
<th>Notification Time (HH:MM):</th>
<th>Notification Date (DD/MM/YY):</th>
</tr>
</thead>
<tbody>
<tr>
<td>Start Time (HH:MM):</td>
<td>Start Date (DD/MM/YY):</td>
</tr>
</tbody>
</table>

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:

<table>
<thead>
<tr>
<th>MW</th>
<th>MINIMUM (MVar +ve for lag, -ve for lead)</th>
<th>MAXIMUM (MVar +ve for lag, -ve for lead)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT RATED MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AT FULL OUTPUT (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AT MINIMUM OUTPUT (MW)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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:

<table>
<thead>
<tr>
<th></th>
<th>MINIMUM (MVar +ve for lag, -ve for lead)</th>
<th>MAXIMUM (MVar +ve for lag, -ve for lead)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AT RATED MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AT 50% OF RATED MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AT 20% OF RATED MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>BELOW 20% OF RATED MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>AT 0% OF RATED MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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 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

<table>
<thead>
<tr>
<th>Notification Time (HH:MM):</th>
<th>Notification Date (DD/MM/YY):</th>
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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:**

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**COMMENTS e.g. reason for submission, predicted end time if known**

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Redeclaration made by (Signature)__________________________________________

Receipt Acknowledgement from **The Company**

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(BC3)
FREQUENCY CONTROL PROCESS

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BC3.1 INTRODUCTION

BC3.1.1 BC3 sets out the procedure for The Company to use in relation to EU Code Users and GB Code Users to undertake System Frequency control. System Frequency will be controlled by response from Gensets (and DC Converters at DC Converter Stations and HVDC Systems) operating in Limited Frequency Sensitive Mode or Frequency Sensitive Mode, by the issuing of instructions to Gensets (and DC Converters at DC Converter Stations and HVDC Systems) and by control of Demand. The requirements for Frequency control are determined by the consequences and effectiveness of the Balancing Mechanism, and accordingly, BC3 is complementary to BC1 and BC2.

BC3.1.2 Inter-Relationship With Ancillary Services

The provision of response (other than by operation in Limited Frequency Sensitive Mode or in accordance with BC3.7.1(c)) in order to contribute towards Frequency control, as described in BC3, by Generators or DC Converter Station owners or HVDC System Owners will be an Ancillary Service. Ancillary Services are divided into three categories, System Ancillary Services Parts 1 and 2 and Commercial Ancillary Services. System Ancillary Services, Parts 1 and 2, are those Ancillary Services listed in CC.8.1 (as applicable to GB Code Users) or ECC8.1 (as applicable to EU Code Users); those in Part 1 of CC.8.1 or Part 1 of ECC.8.1 are those for which the Connection Conditions or European Connection Conditions (as applicable) require the capability as a condition of connection and those in Part 2 are those which may be agreed to be provided by Users and which can only be utilised by The Company if so agreed. Commercial Ancillary Services like those System Ancillary Services set out in Part 2 of CC.8.1 (as applicable to GB Code Users) or Part 2 of ECC.8.1 (as applicable to EU Code Users), may be agreed to be provided by Users and which can only be utilised by The Company if so agreed.

BC3.1.3 The provision of Frequency control services, if any, from an External System via a DC Converter Station or HVDC System will be provided for in the Ancillary Services Agreement and/or Bilateral Agreement with the DC Converter Station owner or HVDC System Owner and/or any other relevant agreements with the relevant EISO.

BC3.1.4 The provision of Frequency control services, if any, from an Offshore Power Station connected to an Offshore Transmission System that includes a Transmission DC Converter will be facilitated (where necessary) through appropriate data signals provided to the Offshore Power Station by the Relevant Transmission Licensee in accordance with the STC.

BC3.2 OBJECTIVE

The procedure for The Company to direct System Frequency control is intended to enable (as far as possible) The Company to meet the statutory requirements of System Frequency control.

BC3.3 SCOPE

BC3 applies to The Company and to GB Code Users and EU Code Users, which in this BC3 means:

(a) GB Generators with regard to their Large Power Stations (except those Large Power Stations with a Registered Capacity less than 50MW comprising of Power Park Modules),

(b) EU Generators with regard to their Large Power Stations,

(c) Network Operators,

(d) DC Converter Station owners and HVDC System Owners,

(e) other providers of Ancillary Services,

(f) Externally Interconnected System Operators.
BC3.4  MANAGING SYSTEM FREQUENCY

BC3.4.1  Statutory Requirements

When The Company determines it is necessary (by having monitored the System Frequency), it will, as part of the procedure set out in BC2, issue instructions (including instructions for Commercial Ancillary Services) in order to seek to regulate System Frequency to meet the statutory requirements of Frequency control. Gensets (except those owned and/or operated by GB Generators comprising of a Power Park Module in a Power Station with a Registered Capacity less than 50MW and those owned and/or operated by GB Generators comprising of a Power Park Module in Scotland before 1 July 2004) and DC Converters at DC Converter Stations or HVDC Systems when transferring Active Power to the Total System, operating in Frequency Sensitive Mode will be instructed by The Company to operate taking due account of the Target Frequency notified by The Company.

BC3.4.2  Target Frequency

The Company will give 15 minutes notice of variation in Target Frequency.

BC3.4.3  Electric Time

The Company will endeavour (in so far as it is able) to control electric clock time to within plus or minus 10 seconds by specifying changes to Target Frequency, by accepting bids and offers in the Balancing Mechanism. Errors greater than plus or minus 10 seconds may be temporarily accepted at The Company's reasonable discretion.

BC3.5  RESPONSE FROM GENSETS (AND DC CONVERTERS AT DC CONVERTER STATIONS AND HVDC SYSTEMS WHEN TRANSFERRING ACTIVE POWER TO THE TOTAL SYSTEM)

BC3.5.1  Capability

Each Genset (except those owned and/or operated by GB Generators and comprising of Power Park Modules in a Power Station with a Registered Capacity less than 50MW and those owned and/or operated by GB Generators and comprising of Power Park Modules in Scotland before 1 July 2004) and each DC Converter at a DC Converter Station and HVDC System must at all times have the capability to operate automatically so as to provide response to changes in Frequency in accordance with the requirements of CC.6.3.7 or ECC.6.3.7 (as applicable) in order to contribute to containing and correcting the System Frequency within the statutory requirements of Frequency control. For DC Converters at DC Converter Stations and HVDC Systems, BC3.1.3 also applies. In addition, each Genset (and each DC Converter at a DC Converter Station and HVDC System) must at all times have the capability to operate in a Limited Frequency Sensitive Mode.

BC3.5.2  Limited Frequency Sensitive Mode

Each Synchronised Genset producing Active Power (and each DC Converter at a DC Converter Station and HVDC System) must operate at all times in a Limited Frequency Sensitive Mode (unless instructed in accordance with BC3.5.4 below to operate in Frequency Sensitive Mode). Operation in Limited Frequency Sensitive Mode must achieve the capability requirement described in CC.6.3.3 (in respect of GB Code Users) and ECC.6.3.3 (in respect of EU Code Users) and for System Frequencies up to 50.4Hz and shall be deemed not to be in contravention of CC.6.3.7 or ECC.6.3.7 (as applicable).

BC3.5.3  (a) Existing Gas Cooled Reactor Plant

The Company will permit Existing Gas Cooled Reactor Plant other than Frequency Sensitive AGR Units to operate in Limited Frequency Sensitive Mode at all times.
(b) Power Park Modules belonging to GB Generators in Operation Before 1 January 2006

The Company will permit Power Park Modules which were in operation before 1 January 2006 and owned and/or operated by GB Generators to operate in Limited Frequency Sensitive Mode at all times. For the avoidance of doubt, Power Park Modules owned and/or operated by GB Generators in England and Wales with a Completion Date on or after 1 January 2006 and Power Park Modules owned and/or operated by GB Generators in operation in Scotland after 1 January 2006 with a completion date after 1 July 2004 and in a Power Station with a Registered Capacity of 50MW or more, will be required to operate in both Limited Frequency Sensitive Mode and Frequency Sensitive Mode of operation depending on System conditions. For the avoidance of doubt, these requirements do not apply to EU Generators.

BC3.5.4 Frequency Sensitive Mode

(a) The Company may issue an instruction to a Genset (or DC Converter at a DC Converter Station or HVDC System) if agreed as described in BC3.1.3 to operate so as to provide Primary Response and/or Secondary Response and/or High Frequency Response (in the combinations agreed in the relevant Ancillary Services Agreement). When so instructed, the Genset or DC Converter at a DC Converter Station or HVDC System must operate in accordance with the instruction and will no longer be operating in Limited Frequency Sensitive Mode, but by being so instructed will be operating in Frequency Sensitive Mode.

(b) Frequency Sensitive Mode is the generic description for a Genset (or DC Converter at a DC Converter Station or HVDC System) operating in accordance with an instruction to operate so as to provide Primary Response and/or Secondary Response and/or High Frequency Response (in the combinations agreed in the relevant Ancillary Services Agreement).

(c) The magnitude of the response in each of those categories instructed will be in accordance with the relevant Ancillary Services Agreement with the Generator or DC Converter Station owner or HVDC System Owner.

(d) Such instruction will continue until countermanded by The Company or until;

(i) the Genset is De-Synchronised; or

(ii) the DC Converter or HVDC System ceases to transfer Active Power to or from the Total System subject to the conditions of any relevant agreement relating to the operation of the DC Converter Station or HVDC System, whichever is the first to occur.

(e) The Company will not so instruct Generators in respect of Existing Gas Cooled Reactor Plant other than Frequency Sensitive AGR Units.

(f) The Company will not so instruct GB Generators in respect of Power Park Modules:

(i) in Scotland in a Power Station with a Completion Date before 1 July 2004; or,

(ii) in a Power Station with a Registered Capacity of less than 50MW.

(iii) in England and Wales with a Completion Date before 1 January 2006.

BC3.5.5 System Frequency Induced Change

A System Frequency induced change in the Active Power output of a Genset (or DC Converter at a DC Converter Station or HVDC System) which assists recovery to Target Frequency must not be countermanded by a Generator or DC Converter Station owner or HVDC System Owner except where it is done purely on safety grounds (relating to either personnel or plant) or, where necessary, to ensure the integrity of the Power Station or DC Converter Station or HVDC System.
BC3.6 RESPONSE TO LOW FREQUENCY

BC3.6.1 Low Frequency Relay initiated Response From Gensets and DC Converters at DC Converter Stations and HVDC Systems

(a) The Company may utilise Gensets (and DC Converters at DC Converter Stations and HVDC Systems) with the capability of Low Frequency Relay initiated response as:

(i) synchronisation and generation from standstill;
(ii) generation from zero generated output;
(iii) increase in generated output;
(iv) increase in DC Converter or HVDC System output to the Total System (if so agreed as described in BC3.1.3);
(v) decrease in DC Converter or HVDC System input from the Total System (if so agreed as described in BC3.1.3);

in establishing its requirements for Operating Reserve.

(b) (i) The Company will specify within the range agreed with Generators and/or EISOs and/or DC Converter Station owners or HVDC System Owners (if so agreed as described in BC3.1.3), Low Frequency Relay settings to be applied to Gensets or DC Converters at DC Converter Stations or HVDC Systems pursuant to BC3.6.1 (a) and instruct the Low Frequency Relay initiated response placed in and out of service.

(ii) Generators and/or EISOs and/or DC Converter Station owners or HVDC System Owners (if so agreed as described in BC3.1.3) will comply with The Company instructions for Low Frequency Relay settings and Low Frequency Relay initiated response to be placed in or out of service. Generators or DC Converter Station owners or HVDC System Owners or EISOs may not alter such Low Frequency Relay settings or take Low Frequency Relay initiated response out of service without The Company’s agreement (such agreement not to be unreasonably withheld or delayed), except for safety reasons.

BC3.6.2 Low Frequency Relay Initiated Response from Demand and other Demand Modification arrangements (which may include a DC Converter Station or HVDC System when Importing Active Power from the Total System)

(a) The Company may, pursuant to an Ancillary Services Agreement, utilise Demand with the capability of Low Frequency Relay initiated Demand reduction in establishing its requirements for Frequency Control.

(b) (i) The Company will specify within the range agreed, the Low Frequency Relay settings to be applied pursuant to BC3.6.2 (a), the amount of Demand reduction to be available and will instruct the Low Frequency Relay initiated response to be placed in or out of service.

(ii) Users will comply with The Company instructions for Low Frequency Relay settings and Low Frequency Relay initiated Demand reduction to be placed in or out of service. Users may not alter such Low Frequency Relay settings or take Low Frequency Relay initiated response out of service without The Company’s agreement, except for safety reasons.

(iii) In the case of any such Demand which is Embedded, The Company will notify the relevant Network Operator of the location of the Demand, the amount of Demand reduction to be available, and the Low Frequency Relay settings.

(c) The Company may also utilise other Demand modification arrangements pursuant to an agreement for Ancillary Services, in order to contribute towards Operating Reserve.
BC3.7 RESPONSE TO HIGH FREQUENCY REQUIRED FROM SYNCHRONISED GENSETS (AND DC CONVERTERS AT DC CONVERTER STATIONS AND HVDC SYSTEMS WHEN TRANSFERRING ACTIVE POWER TO THE TOTAL SYSTEM)

BC3.7.1 Plant in Frequency Sensitive Mode instructed to provide High Frequency Response

(a) Each Synchronised Genset (or each DC Converter at a DC Converter Station or HVDC System) in respect of which the Generator or DC Converter Station owner or HVDC System Owner and/or EISO has been instructed to operate so as to provide High Frequency Response, which is producing Active Power and which is operating above the Designed Minimum Operating Level, is required to reduce 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). The Target Frequency is normally 50.00 Hz except where modified as specified under BC3.4.2.

(b) (i) The rate of change of Active Power output with respect to Frequency up to 50.5 Hz shall be in accordance with the provisions of the relevant Ancillary Services Agreement with each Generator or DC Converter Station owner or HVDC System Owner. If more than one rate is provided for in the Ancillary Services Agreement, The Company will instruct the rate when the instruction to operate to provide High Frequency Response is given.

(ii) The reduction in Active Power output by the amount provided for in the relevant Ancillary Services Agreement must be fully achieved within 10 seconds of the time of the Frequency increase and must be sustained at no lesser reduction thereafter.

(iii) It is accepted that the reduction in Active Power output may not be below the Designed Minimum Operating Level.

(c) In addition to the High Frequency Response provided, the Genset (or DC Converter at a DC Converter Station or HVDC System) must continue to reduce Active Power output in response to an increase in System Frequency above 50.5 Hz at a minimum rate of 2 per cent of output per 0.1 Hz deviation of System Frequency above that level, such reduction to be achieved within five minutes of the rise to or above 50.5 Hz. For a Power Station with a Completion Date after 1st January 2009, this reduction in Active Power should be delivered in accordance with in (i) to (iv) below. For the avoidance of doubt, the provision of this reduction in Active Power output is not an Ancillary Service.

(i) The reduction in Active Power output must be continuously and linearly proportional as far as practical, to the excess of Frequency above 50.5 Hz and must be provided increasingly with time over the period specified in (iii) below.

(ii) As much as possible of the proportional reduction in Active Power output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the Frequency increase above 50.5 Hz.

(iii) The residue of the proportional reduction in Active Power output which results from automatic action of the Genset (or DC Converter at a DC Converter Station or HVDC System) output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes from the time of the Frequency increase above 50.5 Hz.

(iv) Any further residue of the proportional reduction which results from non-automatic action initiated by the Generator or DC Converter Station owner or HVDC System Owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the Frequency increase above 50.5 Hz.
BC3.7.2  **Plant In Limited Frequency Sensitive Mode**

BC.3.7.2.1 **Plant in Limited Frequency Sensitive Mode applicable to GB Code Users**

The following requirements are applicable to **GB Code Users** in respect of **Plant** operating in **Limited Frequency Sensitive Mode**. For the avoidance of doubt, these requirements do not apply to **EU Generators** and **HVDC System Owners** for whom the requirements of BC.3.7.2.2 apply.

(a) Each **Synchronised Genset** (or **DC Converter** at a **DC Converter Station**) operating in a **Limited Frequency Sensitive Mode** which is producing **Active Power** is also required to reduce **Active Power** output in response to **System Frequency** when this rises above 50.4 Hz. In the case of **DC Converters** at **DC Converter Stations**, the provisions of BC3.7.7 are also applicable. For the avoidance of doubt, the provision of this reduction in **Active Power** output is not an **Ancillary Service**. Such provision is known as "**Limited High Frequency Response**".

(b) (i) The rate of change of **Active Power** output must be at a minimum rate of 2 per cent of output per 0.1 Hz deviation of **System Frequency** above 50.4 Hz.

(ii) The reduction in **Active Power** output must be continuously and linearly proportional, as far as is practicable, to the excess of **Frequency** above 50.4 Hz and must be provided increasingly with time over the period specified in (iii) below.

(iii) As much as possible of the proportional reduction in **Active Power** output must result from the frequency control device (or speed governor) action and must be achieved within 10 seconds of the time of the **Frequency** increase above 50.4 Hz.

(iv) The residue of the proportional reduction in **Active Power** output which results from automatic action of the **Genset** (or **DC Converter** at a **DC Converter Station**) output control devices other than the frequency control devices (or speed governors) must be achieved within 3 minutes from the time of the **Frequency** increase above 50.4 Hz.

(v) Any further residue of the proportional reduction which results from non-automatic action initiated by the **Generator** or **DC Converter Station** owner shall be initiated within 2 minutes, and achieved within 5 minutes, of the time of the **Frequency** increase above 50.4 Hz.

(c) Each **GB Code User** in respect of a **Genset** (or **DC Converter** at a **DC Converter Station**) which is providing **Limited High Frequency Response** in accordance with BC3.7.2 must continue to provide it until the **Frequency** has returned to or below 50.4 Hz or until otherwise instructed by **The Company**.

BC.3.7.2.2 **Plant in Limited Frequency Sensitive Mode applicable to EU Code Users**

**EU Code Users** in respect of **Gensets** and **HVDC Systems** are required to operate in **Limited Frequency Sensitive Mode** at all times unless instructed by **The Company** to operate in **Frequency Sensitive Mode**. Where **EU Code Users** **Gensets** and **HVDC Systems** are required to operate in **Limited Frequency Sensitive Mode**, then the requirements of ECC.6.3.7.1 and ECC.6.3.7.2 shall apply. For the avoidance of doubt, the requirements defined in BC.3.7.2.1 do not apply to **New Generators** and **HVDC System Owners**.

BC3.7.3 **Plant Operation to below Minimum Generation or Minimum Stable Operating Level**
(a) As stated in CC.A.3.2 and ECC.A.3.2, steady state operation below Minimum Generation or the Minimum Stable Operating Level or the Minimum Active Power Transmission Capacity is not expected but if System operating conditions cause operation below the Minimum Generation or Minimum Stable Operating Level or the Minimum Active Power Transmission Capacity which gives rise to operational difficulties for the Genset (or DC Converter at a DC Converter Station or HVDC System) then The Company should not, upon request, unreasonably withhold issuing a Bid-Offer Acceptance to return the Power Generating Module and/or Generating Unit and/or CCGT Module and/or Power Park Module or DC Converter or HVDC System to an output not less than the Minimum Generation or the Minimum Stable Operating Level or the Minimum Active Power Transmission Capacity. In the case of a DC Converter or HVDC System not participating in the Balancing Mechanism, then The Company will, upon request, attempt to return the DC Converter or HVDC System to an output not less than Minimum Generation or Minimum Stable Operating Level or the Minimum Active Power Transmission Capacity or to zero transfer or to reverse the transfer of Active Power.

(b) It is possible that a Synchronised Genset (or a DC Converter at a DC Converter Station or HVDC System) which responded as required under BC3.7.1 or BC3.7.2 to an excess of System Frequency, as therein described, will (if the output reduction is large or if the Genset (or a DC Converter at a DC Converter Station or HVDC System) output has reduced to below the Designed Minimum Operating Level or Minimum Regulating Level or the Minimum Active Power Transmission Capacity trip after a time.

(c) All reasonable efforts should in the event be made by the Generator or DC Converter Station owner or HVDC System Owner to avoid such tripping, provided that the System Frequency is below 52Hz.

(d) If the System Frequency is at or above 52Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the Generator or DC Converter Station owner or HVDC System Owner is required to take action to protect the Power Generating Modules and/or Generating Units and/or Power Park Modules or DC Converters or HVDC Systems as specified in CC.6.3.13 or ECC.6.3.13.1.

(e) In the event of the System Frequency becoming stable above 50.5Hz, after all Genset and DC Converter and HVDC System action as specified in BC3.7.1 and BC3.7.2 has taken place, The Company will issue appropriate Bid-Offer Acceptances and/or Ancillary Service instructions, which may include Emergency Instructions under BC2 to trip Gensets (or, in the case of DC Converters at DC Converter Stations or HVDC Systems, to stop or reverse the transfer of Active Power) so that the Frequency returns to below 50.5Hz and ultimately to Target Frequency.

(f) If the System Frequency has become stable above 52Hz, after all Genset and DC Converter or HVDC System action as specified in BC3.7.1 and BC3.7.2 has taken place, The Company will issue Emergency Instructions under BC2 to trip appropriate Gensets (or in the case of DC Converters at DC Converter Stations or HVDC Systems to stop or reverse the transfer of Active Power) to bring the System Frequency to below 52Hz and follow this with appropriate Bid-Offer Acceptances or Ancillary Service instructions or further Emergency Instructions under BC2 to return the System Frequency to below 50.5 Hz and ultimately to Target Frequency.

BC3.7.4 The Generator or DC Converter Station owner or HVDC System Owner will not be in breach of any of the provisions of BC2 by following the provisions of BC3.7.1, BC3.7.2 or BC3.7.3.

BC3.7.5 Information update to The Company

In order that The Company can deal with emergency conditions effectively, it needs as much up to date information as possible and accordingly The Company must be informed of the action taken in accordance with BC3.7.1(c) and BC3.7.2 as soon as possible and in any event within 7 minutes of the rise in System Frequency, directly by telephone from the Control Point for the Power Station or DC Converter Station or HVDC System.
BC3.7.6 (a) **Existing Gas Cooled Reactor Plant**

For the avoidance of doubt, Generating Units within **Existing Gas Cooled Reactor Plant** are required to comply with the applicable provisions of this BC3.7 (which, for the avoidance of doubt, other than for Frequency Sensitive AGR Units, do not include BC3.7.1).

(b) **Power Park Modules In Operation Before 1 January 2006.**

For the avoidance of doubt, GB Generators who own and/or operate **Power Park Modules** which are in operation before 1 January 2006 (irrespective of their Completion Date) are required to comply with the applicable provisions of this BC3.7 (which, for the avoidance of doubt do not include BC3.7.1).

BC3.7.7 **Externally Interconnected System Operators**

The Company will use reasonable endeavours to ensure that, if System Frequency rises above 50.4Hz, and an **Externally Interconnected System Operator** (in its role as operator of the External System) is transferring power into the National Electricity Transmission System from its External System, the amount of power transferred in to the National Electricity Transmission System from the System of that Externally Interconnected System Operator is reduced at a rate equivalent to (or greater than) that which applies for Synchronised Gensets operating in Limited Frequency Sensitive Mode which are producing Active Power. This will be done either by utilising existing arrangements which are designed to achieve this, or by issuing Emergency Instructions under BC2.

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INTRODUCTION

Balancing Code No 4 (BC4) sets out the procedures for:

(a) prequalification requirements for participation in TERRE by BM Participants;
(b) submission of data by BM Participants wishing to take part in TERRE;
(c) validation of data from BM Participants wishing to take part in TERRE;
(d) issuing of RR Instructions; and
(e) publication of TERRE related data.

OBJECTIVE

This procedure facilitates the participation of BM Participants in the TERRE market. Participation in TERRE is voluntary for BM Participants.

SCOPE

BC4 applies to:

(a) The Company;
(b) BM Participants;
(b) Externally Interconnected System Operators; and
(c) Network Operators.

REQUIREMENTS FOR BM PARTICIPANTS WHO WISH TO PARTICIPATE IN TERRE

The Company shall ensure that each relevant Balancing Service prequalification process shall, as a minimum, require the RR provider to submit a self-certification of the RR Minimum Technical Requirements as defined in BC4.4.1 and BC4.4.2.

RR Provider Prequalification Prequalification Timelines

All BM Participants who wish to participate in TERRE must have successfully completed the prequalification process to be a RR provider as detailed in BC5.

Minimum Technical Requirements

All BM Participants who wish to participate in TERRE must have the following capabilities:

(a) BM Participants must have the ability to submit data and receive instructions by the use of electronic data communication facilities as provided for in CC.6.5.8 or ECC.6.5.8.
(b) BM Participants must be capable of following an RR Instruction issued by The Company.
(c) BM Participants must be able to provide Physical Notifications.
(d) BM Participants must be able to provide a subset of Dynamic Parameters (as detailed in BC4.5.2).
(e) BM Participants must provide operational metering for their total output and for any individual component that may have an output greater than 1MW. This metering must have the following accuracy;
   a. For a BM Unit with either a Generation Capacity greater than 100MW or Demand Capacity greater than 100MW, a metering accuracy better than 0.5%.
b. For a BM Unit with a Generation Capacity greater than 10MW but less than or equal to 100MW or Demand Capacity greater than 10MW but less than or equal to 100MW, a metering accuracy better than 1%.

c. For all other BM Units, an accuracy better than 2.5% is required.

(f) BM Participants must have the ability to inform The Company if their availability changes using Export and Import Limits.

(g) For BM Participants connected within a User System, BM Participants must be capable of informing Network Operators of their availability and activation in realtime if required.

BC4.3 Prequalification Timelines

The following minimum timescales for the prequalification process apply:

(a) Within 8 weeks of a formal application from the BM Participant, The Company shall confirm the application is complete (from the perspective of information provision).

(b) If the application is incomplete, the BM Participant shall provide the missing evidence within 4 weeks of the request from The Company or it will be presumed that the application has been withdrawn.

(c) Within 3 months of confirming that all information has been provided, The Company shall confirm if the potential BM Participant meets the requirements in BC4.4.2. For the avoidance of doubt, The Company will not carry out independent tests but will review the evidence provided.

BC4.4 Requalification criteria

Under certain conditions, an BM Participant must requalify.

(a) Every five years, a BM Participant must requalify to the technical requirements in BC4.4.2 and according to the timescales in BC4.4.3.

(b) If at any time, a BM Participant becomes aware of changes to the configuration forming the BM Unit, that means the minimum technical requirements in BC4.4.2 can no longer be met, then that BM Participant must withdraw from TERRE and must requalify.

BC4.5 SUBMISSION OF TERRE RELATED DATA BY BM PARTICIPANTS

BC4.5.1 Communication from BM Participants to The Company

(a) Submission of data specified in BC4.5.2 will be by use of electronic data communications facilities, as provided for in CC.6.5.8 or ECC.6.5.8.

(b) In the event of a failure of the electronic data communication facilities, the data used in the TERRE auction will be based on the most recent data received and acknowledged by The Company. In the event of missing data, it will be assumed the BM Participant did not wish to submit data for the relevant TERRE Auction Period.

(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 BC4.5.1(b) (where it is termed a "failure") in relation to a pre-TERR Gate Closure:

(i) If a BM Participant has submitted Physical Notifications and a TERRE Bid for a TERRE Auction Period the BM Participant 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 TERRE 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 Participants data should be attempted. Plant failure or similar problems causing significant deviation from the Physical Notification should be notified to The Company by the submission of a revision to Export and Import Limits in relation to the RR Provider so affected;

(ii) No data will be transferred from The Company to the Balancing Mechanism Reporting Agent (BMRA) until the communication facilities are re-established.

BC4.5.2 RR Provider Data submissions before TERRE Gate Closure

To participate in a TERRE auction, a BM Participant must have prequalified and must submit a TERRE Bid covering at least one of the TERRE Activation Periods within the TERRE Auction Period.

In addition to a valid TERRE Bid, a sub-set of Balancing Mechanism parameters are also required covering the TERRE Auction Period and the Settlement Periods immediately before and after the TERRE Auction Period (to allow ramping before and after).

If a BM Participant is active in the Balancing Mechanism the only additional data needed to participate in a TERRE auction is a valid TERRE Bid covering the relevant times.

For a BM Participant that is not active in the Balancing Mechanism, the following subset of parameters are required with exceptions as noted below:

(a) Physical Notifications

Physical Notifications follow the same format and rules as covered in BC1 and BC2 with the following exceptions;

(1) A BM Participant that is not active in the Balancing Mechanism but wishes to participate in TERRE is only required to have submitted Physical Notifications covering the TERRE Auction Period and the Settlement Periods immediately before and after the TERRE Auction Period for which they have submitted a TERRE Bid.

(2) Defaulting rules as described in the Data Validation, Consistency and Defaulting Rules will only apply to Settlement Periods for which the BM Participant previously submitted Physical Notifications for the previous Operational Day.

(b) Export and Import Limits

For a BM Participant that is not active in the Balancing Mechanism but wishes to participate in TERRE, these are the same as described in BC1 and BC2.

(c) Run Up Rate and Run Down Rates

For a BM Participant that is not active in the Balancing Mechanism but wishes to participate in TERRE these are the same as described in BC1 and BC2.

(d) For a BM Participant that is not active in the Balancing Mechanism but wishes to participate in TERRE, the other Dynamic Parameters listed in BC1.A.1.5 are not required.

TERRE Bids must follow the formats and rules in the TERRE Data Validation and Consistency Rules.
BC4.5.3 Re-submission of parameters by BM Participants before TERRE Gate Closure

The rules outlined in BC1 and BC2 for the revision of Physical Notifications, Export and Import Limits, Run Up Rates and Run Down Rates also apply for TERRE.

TERRE Bids can be revised up to TERRE Gate Closure in order to be used in the TERRE auction (as described in the TERRE Data Validation and Consistency Rules).

BC4.5.4 Defaulting rules for TERRE Bids

TERRE Bids will not be defaulted using previously submitted values. This is due to the ability to link TERRE Bids and the re-use of sequence numbers. Hence a BM Participant wishing to participate in a particular TERRE auction must submit RR Bids specifically covering the relevant TERRE Activation Periods.

BC4.6 Processing of TERRE Bids before passing to the TERRE Central Platform

BC4.6.1 Cases where a TERRE Bid will be Restricted

TERRE Bids will be passed to the TERRE Central Platform but will be flagged as Restricted under the following cases:-

(a) Data within the submission does not conform to formats required as detailed in the TERRE Data Validation and Consistency Rules (e.g. missing or incorrect keywords, data in the wrong order, corrupted files etc).

(b) If a TERRE Bid does not have a corresponding Physical Notification, the TERRE Bid will be flagged as Restricted.

(c) If a TERRE Bid will result in violating a System Constraint, it will be flagged as Restricted.

(d) If a BM Participant has already been instructed for an Ancillary Service or for Reserve, a TERRE Bid may need to be flagged as Restricted. For the avoidance of doubt – participation in TERRE does not exclude an BM Participant from offering other services to The Company but on occasions if there are conflicts between services, The Company may have to flag these TERRE Bids as Restricted.

BC4.7 Instructing BM Participants

BC4.7.1 Communication from The Company to BM Participants

For the purposes of communication, an RR Instruction will follow the same format as a Bid-Offer Acceptance and so the rules of BC2.7 also apply for RR Instructions.

BC4.7.2 Creating RR Instructions from RR Acceptances

Results from the TERRE Central Platform are returned to The Company in the form of RR Acceptances.

RR Acceptances do not include physical ramps and so Run Up Rates and Run Down Rates will be used to create RR Instructions.

In order to comply with all of the RR Acceptances for a BM Participant, several RR Instructions may be required.

RR instructions will ramp BM Participants from their Committed Level, hold them at the required output level, and then return the BM Participant back to the Committed Level.

The TERRE market wishes to incentivise RR Instructions which ramp within +/-5 minutes of the start and end of the TERRE Activation Periods. Hence, where possible, Run Up Rates and Run Down Rates will be applied so that ramping is symmetric around the start and end of the TERRE Activation Periods.

However the TERRE Product allows for up to 30 minute ramping to and from full activation and so for the first and final ramps up to 30 minutes of ramping can be used for creating an RR Instruction.

Details of how RR Instructions will be created can be found in the TERRE Instruction Guide.
BC4.7.3 Cases where RR Instructions may not be issued

In the time between receiving TERRE Bids and the RR Acceptances being returned to The Company, system conditions may require the issuing of a Bid Offer Acceptance to the BM Participant for which the RR Acceptance applies.

In these cases, it may be necessary to not issue an RR Instruction to the BM Participant or to modify the RR Instruction so that it is compatible with the Bid Offer Acceptance that has been previously been issued to the BM Participant.

This situation can only arise for a BM Participant which is also active in the Balancing Mechanism.

The following may apply:

(a) If the Bid Offer Acceptance is in the same direction as the RR Instruction but the MW levels of the RR Instruction are less than the Committed Level after the Bid Offer Acceptance is applied, the RR Instruction will not be issued.

(b) If the Bid Offer Acceptance is in the same direction as the RR Instruction but the MW levels of the RR Instruction are greater than the Committed Level after the Bid Offer Acceptance is applied the RR Instruction will be issued relative to the Committed Level.

(c) If the Bid Offer Acceptance is in the opposite direction to the RR Instruction the RR instruction will not be issued.

BC4.7.4 Infeasibility of RR Acceptances

If the RR Acceptances for an BM Participant are not consistent with the Physical Notifications and the Run Up Rates and Run Down Rates, then The Company will adjust the MW levels so that RR Instructions can be created using the declared parameters.

Details of how these infeasibility rules will be applied are contained in the TERRE Instruction Guide.

BC4.8 Publication of TERRE Data

BC4.8.1 Publication of Data at the National level

The Company shall provide data in accordance with the requirements of the BSC. The following data items will be provided:

(a) TERRE Bids and details of those restricted

(b) Final Physical Notifications

(c) RR activations

(d) RR Instructions

(e) Interconnector Volumes per 15 minute period of the TERRE Activation Period

(f) The TERRE clearing price

(g) Volume of GB need met

BC4.9 Outages of computer systems leading to the suspension of the TERRE market
The TERRE market operates in short processing times meaning that Planned Maintenance Outages or unplanned computer system failures can result in the suspension of the TERRE market.

Suspension of the TERRE market in GB will occur in the following circumstances:

(a) Loss of communication from The Company to the TERRE Central Platform
(b) Failure of the TERRE Central Platform to produce RR Acceptances
(c) Loss of communication from the TERRE Central Platform to The Company
(d) Loss of electronic logging devices to a large number of BM Participants

BC4.10 TERRE Market Suspension

The TERRE market shall be suspended in GB when one of the following circumstances arises:

(a) Suspension of the Balancing Mechanism in accordance with OC9.4.6; or
(b) Outages of computer systems leading to the suspension of the TERRE market as provided for in BC4.9; or
(c) Operators of the TERRE Central Platform notify The Company that the TERRE market has been or is to be suspended.

Where the TERRE market has been suspended as a result of item (a) above, or is to be or has been suspended as a result of items (b) or (c) above, The Company will as soon as reasonably practical, inform Users and the BSCCo that the TERRE market is to be or has been suspended. The Company will notify Users and the BSCCo if the TERRE market suspension arose as a result of a Black Start event or another condition in accordance with the requirements of the BSC.

In the case of TERRE market suspension under BC4.10 (b) or (c), The Company shall (as soon as is practicable) determine, in its reasonable opinion, the time and date from when the TERRE market is to be suspended. The Company shall also notify Users and the BSCCo of the time of TERRE market suspension and the reason for the suspension.

Where the TERRE market has been suspended, it will not be resumed until the start of a defined Settlement Period which shall be determined:

i) by the BSC Panel in accordance with section G3.1.8 of the BSC (in the case of a Black Start event); or
ii) by section Q.5.A of the BSC (in the case of TERRE market suspension for any other reason other than Black Start).

In the case of TERRE market suspension as a result of a Black Start event, as provided for under BC4.10(a), Users shall use reasonable endeavours to submit TERRE Bids ten hours prior to the start of the Settlement Period determined by the BSC Panel in accordance with paragraph G3.1.8 of the BSC and as notified by The Company to Users in preparation for the resumption of the TERRE market.

In the case of TERRE market suspension as a result of another event as provided for under BC4.10(b) or BC4.10(c), Users shall use reasonable endeavours to submit TERRE Bids as soon as possible after notification from The Company of the Settlement Period from when the TERRE market is to be resumed.

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BC5.1 PREQUALIFICATION

The Company shall list the current status and dates of potential status changes of Balancing Services as Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) or Replacement Reserves (RR) or existing GB.

Where a Balancing Service has been approved as a Standard Product or Specific Product providing FCR, FRR or RR, The Company shall ensure that prequalification processes for that Balancing Service follows the processes as set out here. The Company shall ensure that each relevant Balancing Service requires a formal application from the FCR, FRR or RR provider to prequalify.

Where the Connection Conditions or European Connection Conditions require the capability as a condition of connection, the connection application may be understood to fulfil this formal application if so requested by the connecting party. For the avoidance of doubt, this does not compel a party to pre-qualify as part of their connection conditions.

BC5.1.1 Prequalification Timelines

BC5.1.1.1 The following minimum timescales shall be apply to the FCR, FRR and RR prequalification processes;

(a) Within 8 weeks of a formal application from the FCR, FRR or RR provider The Company shall confirm the application is complete or incomplete (from the perspective of information provision)

(b) If the application is incomplete the FCR, FRR, or RR provider shall submit the additional required information within 4 weeks of a request from The Company or it will be presumed that the application has been withdrawn.

(c) For units connected to distribution networks, The Company shall liaise with the relevant DNO(s) to identify potential limitations imposed on the proposed Balancing Services Provider by the distribution networks.

(d) Within 3 months of confirming that all information has been provided, The Company shall confirm if the potential FCR, FRR or RR provider meets the requirements in BC5.2.1, BC5.3.1 or BC5.4.1 respectively.

BC5.1.1.2 The Company shall re-assess the qualification of FCR, FRR or RR providing units or groups:

(a) at least once every 5 years;
(b) in case the technical or availability requirements or the equipment has changed; and
(c) in the case of FCR providing units or groups, in case of modernisation of the equipment related to FCR activation.

BC5.2 FCR PREQUALIFICATION PROCESS

The Company shall ensure that each relevant Balancing Service prequalification
process shall, as a minimum, require the FCR provider to submit a self-certification of the FCR Minimum Technical Requirements as defined in BC5.2.1.

A transitional period for the introduction of FCR Minimum Technical Requirements, as defined in BC5.2.1 and BC5.2.2, shall apply for those FCR providers who are not an EU Code User.

**BC5.2.1 FCR Minimum Technical Requirements**

Each FCR provider shall have the right to aggregate the respective data for more than one FCR providing unit if the maximum power of the aggregated units is below 1.5 MW and a clear verification of activation of FCR is possible.

Each FCR providing unit and each FCR providing group shall:

(a) activate the agreed FCR by means of a proportional governor or load controller reacting to Frequency deviations or alternatively based on a monotonic piecewise linear power-frequency characteristic in case of relay activated FCR.

(b) be capable of activating FCR within the Frequency ranges specified in the in CC.6.1.3 or ECC.6.1.2.1.2.

(c) and comply with the following properties

(i) Maximum combined effect of inherent Frequency Response Insensitivity and possible intentional Frequency Response Deadband of the governor or load controller of the FCR providing units or FCR providing groups of ±15 mHz

(ii) FCR full activation time of 10 s

(iii) FCR full activation Frequency deviation of ±500 mHz

(d) Specify the limitations of the energy reservoir of its FCR providing units or FCR.

(e) Each FCR provider shall be capable of making available to The Company, for each of its FCR providing units and FCR providing groups, at least the following information:

(i) time-stamped status indicating if FCR is on or off;

(ii) time-stamped active power data needed to verify FCR activation, including time-stamped instantaneous Active Power; and

(iii) droop of the governor or load controller for Type C Power Generating Modules and Type D Power Generating Modules acting as FCR providing units, or its equivalent parameter for FCR providing groups consisting of Type A Power-Generating Modules and/or Type B Power Generating Modules, and/or Demand Units with Demand Response Active Power.

(f) An FCR provider shall guarantee the continuous availability of FCR, with the exception of a forced outage of a FCR providing unit, during the period of time in which it is obliged to provide FCR.

(g) Each FCR provider shall inform The Company, as soon as possible, about any changes in the actual availability of its FCR providing unit and/or its FCR providing group, in whole or in part, relevant for the results of this prequalification.

**BC5.2.2**

In addition to the requirements in BC5.2.1, where a relevant Balancing
Service is provided by reserve providing groups or units located in the distribution systems, The Company shall ensure that the prequalification process requires the following to be specified:

(a) voltage levels and connection points of the reserve providing units or groups;
(b) the DNO(s) who operate the distribution systems to which the reserve providing units or groups are connected;
(c) the type of Active Power reserves;
(d) the maximum reserve capacity provided by the reserve providing units or groups at each connection point; and
(e) the maximum rate of change of Active Power for the reserve providing units or groups.

The relevant DNOs will identify potential distribution network restrictions, based on technical reasons, on the provision of the proposed Balancing Service by the reserve providing groups or units.

BC 5.3 FRR PREQUALIFICATION PROCESS

The Company shall ensure that each relevant Balancing Service prequalification process shall, as a minimum, require the FRR provider to submit a self-certification of the FRR Minimum Technical Requirements as defined in BC5.3.1 and BC5.3.2.

BC5.3.1 FRR Minimum Technical Requirements

Each FRR providing unit and each FRR providing group shall;

(a) activate FRR in accordance with the setpoint received from The Company;
(b) ensure that the FRR activation of the FRR providing units within a reserve providing group can be monitored. For that purpose the FRR provider shall be capable of supplying to The Company real-time measurements of the connection point or another point of interaction agreed with The Company concerning:
   (i) time-stamped scheduled Active Power output;
   (ii) time-stamped instantaneous Active Power for:
         — each FRR providing unit,
         — each FRR providing group, and
         — each Power Generating Module or Demand unit of a FRR providing group with a maximum Active Power output larger than or equal to 1.5 MW;
(c) a FRR providing unit or FRR providing group for automatic FRR shall have an automatic FRR activation delay not exceeding 30 seconds;
(d) be capable of activating its complete manual reserve capacity on FRR within the FRR full activation time;
(e) fulfil the FRR availability requirements;
(f) fulfil the ramping rate requirements
(g) inform The Company about a reduction of the actual availability of its FRR providing unit or its FRR providing group or a part of its FRR providing group as soon as possible.
BC5.3.2 In addition to the requirements in BC5.3.1, where a relevant Balancing Service is provided by reserve providing groups or units located in the distribution systems, The Company shall ensure that the prequalification process requires the following to be specified:

(a) voltage levels and connection points of the reserve providing units or groups;
(b) the DNO(s) who operate the distribution systems to which the reserve providing units or groups are connected;
(c) the type of Active Power reserves;
(d) the maximum reserve capacity provided by the reserve providing units or groups at each connection point; and
(e) the maximum rate of change of Active Power for the reserve providing units or group

The relevant DNOs will identify potential distribution network restrictions, based on technical reasons, on the provision of the proposed Balancing Service by the reserve providing groups or units.

BC5.4 RR PREQUALIFICATION PROCESS

The Company shall ensure that each relevant Balancing Service prequalification process shall, as a minimum, require the RR provider to submit a self-certification of the RR Minimum Technical Requirements as defined in BC5.4.1 and BC5.4.2.

BC5.4.1 RR Minimum Technical Requirements

Each RR providing unit and each RR providing group shall:

(a) activate RR in accordance with the setpoint received from The Company;
(b) ensure activation of complete reserve capacity on RR within the activation time defined by The Company;
(c) ensure de-activation of RR according to the setpoint received from The Company;
(d) ensure that the RR activation of the RR providing units within a reserve providing group can be monitored. For that purpose, the RR provider shall be capable of supplying to The Company real-time measurements of the connection point or another point of interaction agreed with The Company:

(i) the time-stamped scheduled Active Power output, for each RR providing unit and group and for each Power Generating Module or Demand unit of a RR providing group with maximum Active Power output larger than or equal to 1.5 MW;

(ii) the time-stamped instantaneous Active Power, for each RR providing unit and group, and for each Power Generating Module or Demand unit of a RR providing group with a maximum Active Power output greater than or equal to 1.5 MW;

(e) ensure fulfilment of the RR availability requirements
(f) inform The Company about a reduction of the actual availability or a forced outage of its RR providing unit or its RR providing group or a part of its RR providing group as soon as possible.

BC5.4.2 In addition to the requirements in BC5.4.1, where a relevant Balancing Service is provided by a reserve providing groups or units located in the distribution systems, The Company shall ensure that the prequalification process requires the following to be specified:

(a) voltage levels and connection points of the reserve providing units or groups;
(b) the DNO(s) who operate the distribution systems to which the reserve providing units or groups are connected;
(c) the type of Active Power reserves;
(d) the maximum reserve capacity provided by the reserve providing units or groups at each connection point; and
(e) the maximum rate of change of Active Power for the reserve providing units or groups.

The relevant DNOs will identify potential distribution network restrictions on the provision of the proposed Balancing Service by the reserve providing groups or units.

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<td>79</td>
</tr>
</tbody>
</table>
INTRODUCTION

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 DRC. 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.

The DRC identifies the section of the Grid Code under which each item of data is required.

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.

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).

The categorisation of data into DPD I and DPD II is indicated in the DRC below.

OBJECTIVE

The objective of the DRC is to:

List and collate all the data to be provided by each category of User to The Company under the Grid Code.

List all the data to be provided by The Company to each category of User under the Grid Code.

SCOPE

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;
(f) Externally Interconnected System Operators;
(g) Interconnector Users;
(h) BM Participants; and
(i) Pumped Storage Generators and Generators in respect of Electricity Storage Modules.

For the avoidance of doubt, the DRC applies to both GB Code Users and EU Code Users.

DATA CATEGORIES AND STAGES IN REGISTRATION

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 User’s Data

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 20 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 and storage 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
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.6.1.20 Schedule 20 – Grid Forming Plant Data
Comprising information relating to Grid Forming Plant

DRC.6.2 The Schedules applicable to each class of User are as follows:

<table>
<thead>
<tr>
<th>User</th>
<th>Schedule</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generators with Large Power Stations</td>
<td>1, 2, 3, 4, 9, 14, 15, 16, 19</td>
</tr>
<tr>
<td>Generators with Medium Power Stations (see notes 2, 3, 4)</td>
<td>1, 2 (part), 9, 14, 15, 19</td>
</tr>
<tr>
<td>Generators with Small Power Stations directly connected to the National Electricity Transmission System</td>
<td>1, 6, 14, 15, 19</td>
</tr>
<tr>
<td>Generators undertaking OTSDUW (see note 5)</td>
<td>18, 19</td>
</tr>
<tr>
<td>All Users connected directly to the National Electricity Transmission System</td>
<td>5, 6, 9</td>
</tr>
<tr>
<td>All Users connected directly to the National Electricity Transmission System other than Generators</td>
<td>10, 11, 13, 17</td>
</tr>
<tr>
<td>All Users connected directly to the National Electricity Transmission System with Demand</td>
<td>7, 9</td>
</tr>
<tr>
<td>A Pumped Storage Generator, a Generator in respect of one or more Electricity Storage Modules and an Externally Interconnected System Operator and Interconnector Users</td>
<td>12 (as marked)</td>
</tr>
<tr>
<td>All Suppliers</td>
<td>12</td>
</tr>
<tr>
<td>All Network Operators</td>
<td>12</td>
</tr>
<tr>
<td>All BM Participants</td>
<td>8</td>
</tr>
<tr>
<td>All DC Converter Station owners</td>
<td>1, 4, 9, 14, 15, 19</td>
</tr>
</tbody>
</table>

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

% on MVA = % on Rated MVA

% on 100 = % on 100 MVA

DPD = Detailed Planning Data

RC = Registered Capacity

MC = Maximum Capacity

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.
### 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.
  - **Demand** at specified time of annual peak half hour of National Electricity Transmission System Demand at Annual ACS Conditions.
  - **Demand** at specified time of annual minimum half-hour of National Electricity Transmission System Demand.

(Additional Demand supplied through the unit transformers to be provided below)

### INDIVIDUAL GENERATING UNIT (OR AS THE CASE MAY BE, SYNCHRONOUS POWER GENERATING MODULE OR CCGT MODULE) DATA

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL CAT.</th>
<th>GENERATING UNIT OR STATION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>CUSC Contract</td>
<td>F.Yr. 0</td>
</tr>
<tr>
<td>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)</td>
<td>Text</td>
<td>□</td>
<td>SPD</td>
</tr>
<tr>
<td>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)</td>
<td>Section Number</td>
<td>□</td>
<td>SPD</td>
</tr>
<tr>
<td>Type of Unit (steam, Gas Turbine Combined Cycle Gas Turbine Unit, tidal, wind, storage type etc.)</td>
<td>□</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

(PC.A.3.2.2 (h), PC.A.3.4.4)
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))

<table>
<thead>
<tr>
<th>INDIVIDUAL SYNCHRONOUS POWER GENERATING MODULE</th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th>SPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>G1</td>
<td>G2</td>
<td>G3</td>
<td>G4</td>
<td>G5</td>
<td>G6</td>
<td>STN</td>
</tr>
<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA to RTL</td>
<td>DATA CAT.</td>
<td>GENERATING UNIT (OR CCGT MODULE, AS THE CASE MAY BE)</td>
<td></td>
<td></td>
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<tr>
<td>------------------</td>
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<td>------------</td>
<td>----------</td>
<td>-----------------------------------------------------</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated MVA (PC.A.3.3.1)</td>
<td>MVA</td>
<td>CUSC Cont ract</td>
<td>SPD+</td>
<td>G1</td>
<td>G2</td>
<td>G3</td>
</tr>
<tr>
<td>Rated MW (PC.A.3.3.1)</td>
<td>MW</td>
<td>CUSC App. Form</td>
<td>SPD+</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated terminal voltage (PC.A.5.3.2.(a) &amp; PC.A.5.4.2 (b))</td>
<td>kV</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>*Performance Chart at Onshore Synchronous Generating Unit stator terminals (PC.A.3.2.2(f)(i))</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Performance Chart of the Offshore Synchronous Generating Unit at the Offshore Grid Entry Point (PC.A.3.2.2(f)(iii))</td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>* Synchronous Generating Unit Performance Chart (PC.A.3.2.2(f))</td>
<td></td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>* Power Generating Module Performance Chart of the Synchronous Power Generating Module (PC.A.3.2.2(f))</td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>* Maximum terminal voltage set point (PC.A.5.3.2.(a) &amp; PC.A.5.4.2 (b))</td>
<td>kV</td>
<td>DPD I</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Terminal voltage set point step resolution – if not continuous (PC.A.5.3.2.(a) &amp; PC.A.5.4.2 (b))</td>
<td>kV</td>
<td>DPD I</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>*Output Usable (on a monthly basis) (PC.A.3.2.2(b))</td>
<td>MW</td>
<td>SPD+</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Turbo-Generator inertia constant (for synchronous machines) (PC.A.5.3.2(a))</td>
<td>MW secs</td>
<td>SPD+</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Short circuit ratio (synchronous machines) (PC.A.5.3.2(a))</td>
<td>/MVA</td>
<td>SPD+</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Normal auxiliary load supplied by the Generating Unit at rated MW output (PC.A.5.2.1)</td>
<td>MW</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated field current at rated MW and MVAR output and at rated terminal voltage (PC.A.5.3.2 (a))</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Field current open circuit saturation curve (as derived from appropriate manufacturers' test certificates): (PC.A.5.3.2 (a))</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>120% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>110% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>100% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>90% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>80% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>70% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>60% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>50% rated terminal volts</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>IMPEDANCES:</td>
<td></td>
<td></td>
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<tr>
<td>(Unsaturated)</td>
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</tr>
<tr>
<td>Direct axis synchronous reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>DPD I</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct axis transient reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>SPD+</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>Direct axis sub-transient reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>DPD I</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Quad axis synch reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>DPD I</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Quad axis sub-transient reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>DPD I</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stator leakage reactance (PC.A.5.3.2(a))</td>
<td>% on MVA</td>
<td>DPD I</td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

(see OC2 for specification)
| 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.
### Time Constants

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data to RTL CAT</th>
<th>Data to CUSC Cat</th>
<th>Generating Unit or Station Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>(Short-circuit and Unsaturated)</td>
<td></td>
<td></td>
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<tr>
<td>Direct axis transient time constant</td>
<td>S</td>
<td>□</td>
<td>DPD I</td>
<td>G1, G2, G3, G4, G5, G6, STN</td>
</tr>
<tr>
<td>(PC.A.5.3.2(a))</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Direct axis sub-transient time constant</td>
<td>S</td>
<td>□</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>(PC.A.5.3.2(a))</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Quadrature axis sub-transient time constant</td>
<td>S</td>
<td>□</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>(PC.A.5.3.2(a))</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stator time constant</td>
<td>S</td>
<td>□</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>(PC.A.5.3.2(a))</td>
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### MECHANICAL PARAMETERS

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<th>Units</th>
<th>Data to RTL CAT</th>
<th>Data to CUSC Cat</th>
<th>Generating Unit or Station Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>The number of turbine generator masses</td>
<td>□</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Diagram showing the Inertia and parameters for each turbine generator mass</td>
<td>Kgm²</td>
<td>□</td>
<td>DPD II</td>
<td></td>
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<tr>
<td>for the complete drive train</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Diagram showing Stiffness constants and parameters between each turbine generator</td>
<td>Nm/rad</td>
<td>□</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>mass for the complete drive train</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of poles</td>
<td>%</td>
<td>□</td>
<td>DPD II</td>
<td></td>
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<tr>
<td>Relative power applied to different parts of the turbine</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Torsional mode frequencies</td>
<td>Hz</td>
<td>□</td>
<td>DPD II</td>
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<td>Modal damping decrement factors for the different mechanical modes</td>
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### GENERATING UNIT STEP-UP TRANSFORMER

<table>
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<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data to RTL CAT</th>
<th>Data to CUSC Cat</th>
<th>Generating Unit or Station Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated MVA (PC.A.3.3.1 &amp; PC.A.5.3.2)</td>
<td>MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Voltage Ratio (PC.A.5.3.2)</td>
<td>-</td>
<td>□</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>Positive sequence reactance: (PC.A.5.3.2)</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Min tap</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Nominal tap</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Positive sequence reactance: (PC.A.5.3.2)</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Min tap</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Nominal tap</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Zero phase sequence reactance</td>
<td>% on MVA</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>(PC.A.5.3.2)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Tap change range (PC.A.5.3.2)</td>
<td>+% / -%</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Tap change step size (PC.A.5.3.2)</td>
<td>%</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>Tap changer type: on-load or off-circuit (PC.A.5.3.2)</td>
<td>On/Off</td>
<td>□</td>
<td>SPD+</td>
<td></td>
</tr>
<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA to RTL</td>
<td>DATA CAT.</td>
<td>GENERATING UNIT OR STATION DATA</td>
</tr>
<tr>
<td>----------------------------------------------------------------------------------</td>
<td>-------</td>
<td>-------------</td>
<td>----------</td>
<td>---------------------------------</td>
</tr>
<tr>
<td>EXCITATION:</td>
<td></td>
<td></td>
<td>G1</td>
<td>G2</td>
</tr>
<tr>
<td>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.</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Option 1</td>
<td></td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>DC gain of Excitation Loop (PCA.5.3.2(c))</td>
<td>□</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max field voltage (PCA.5.3.2(c))</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Min field voltage (PCA.5.3.2(c))</td>
<td>V</td>
<td>DPD II</td>
<td></td>
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</tr>
<tr>
<td>Rated field voltage (PCA.5.3.2(c))</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Max rate of change of field volts: (PCA.5.3.2(c))</td>
<td>V/Sec</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of Excitation Loop (PCA.5.3.2(c))</td>
<td>Diagram □ DPD II (please attach)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dynamic characteristics of over- excitation limiter (PCA.5.3.2(c))</td>
<td>□</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dynamic characteristics of under-excitation limiter (PCA.5.3.2(c))</td>
<td>□</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Option 2</td>
<td></td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>Exciter category, e.g. Rotating Exciter, or Static Exciter etc (PCA.5.3.2(c))</td>
<td>Text</td>
<td>SPD</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excitation System Nominal (PCA.5.3.2(c)) response V</td>
<td>Sec¹</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Rated Field Voltage (PCA.5.3.2(c)) Uᵦₙ</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>No-load Field Voltage (PCA.5.3.2(c)) Uₙ₀</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excitation System On-Load (PCA.5.3.2(c)) V</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Positive Ceiling Voltage Uₚₚₚₚ</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Excitation System No-Load (PCA.5.3.2(c)) V</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Negative Ceiling Voltage Uₚₚₚₚ</td>
<td>V</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power System Stabiliser (PSS) fitted (PCA.3.4.2)</td>
<td>Yes/No</td>
<td>SPD</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stator Current Limit (PCA.5.3.2(c))</td>
<td>A</td>
<td>DPD II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of Excitation System (PCA.5.3.2(c)) (including PSS if fitted) described in block diagram form showing transfer functions of individual elements.</td>
<td>Diagram □ DPD II</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of Over-excitation Limiter (PCA.5.3.2(c)) described in block diagram form showing transfer functions of individual elements.</td>
<td>Diagram □ DPD II</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of Under-excitation Limiter (PCA.5.3.2(c))</td>
<td>□</td>
<td>DPD II</td>
<td></td>
<td></td>
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</tbody>
</table>
described in block diagram form showing transfer functions of individual elements.
## 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.

### Option 1

**GOVERNOR PARAMETERS (REHEAT UNITS) (PC.A.5.3.2(d) – Option 1(ii))**

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data to RTL</th>
<th>Data Cat.</th>
<th>Generating Unit or Station Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>HP Governor average gain</td>
<td>MW/Hz</td>
<td>☐</td>
<td>DPD II</td>
<td>G1 G2 G3 G4 G5 G6 STN</td>
</tr>
<tr>
<td>Speeder motor setting range</td>
<td>Hz</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP governor valve time constant</td>
<td>S</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP governor valve opening limits</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP governor valve rate limits</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Re-heat time constant (stored Active Energy in reheater)</td>
<td>S</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>IP Governor average gain</td>
<td>MW/Hz</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>IP Governor setting range</td>
<td>Hz</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>IP Governor time constant</td>
<td>S</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>IP governor valve opening limits</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>IP governor valve rate limits</td>
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<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Details of acceleration sensitive elements HP &amp; IP in governor loop</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td>(please attach)</td>
</tr>
<tr>
<td>Governor block diagram showing transfer functions of individual elements</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td>(please attach)</td>
</tr>
</tbody>
</table>

**GOVERNOR (Non-reheat steam and Gas Turbines) (PC.A.5.3.2(d) – Option 1(ii))**

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data to RTL</th>
<th>Data Cat.</th>
<th>Generating Unit or Station Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Governor average gain</td>
<td>MW/Hz</td>
<td>☐</td>
<td>DPD II</td>
<td>G1 G2 G3 G4 G5 G6 STN</td>
</tr>
<tr>
<td>Speeder motor setting range</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Time constant of steam or fuel governor valve</td>
<td>S</td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Governor valve opening limits</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Governor valve rate limits</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Time constant of turbine</td>
<td>S</td>
<td>☐</td>
<td>DPD II</td>
<td>(please attach)</td>
</tr>
<tr>
<td>Governor block diagram</td>
<td></td>
<td>☐</td>
<td>DPD II</td>
<td>(please attach)</td>
</tr>
<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA to RTL</td>
<td>DATA CAT.</td>
<td>GENERATING UNIT OR STATION DATA</td>
</tr>
<tr>
<td>------------------</td>
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<td>-------------</td>
<td>-----------</td>
<td>-------------------------------</td>
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<tr>
<td><em>(PC.A.5.3.2(d) – Option 1(iii))</em> BOILER &amp; STEAM TURBINE DATA*</td>
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<tr>
<td>Boiler time constant (Stored Active Energy)</td>
<td>S</td>
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<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP turbine response ratio: (Proportion of Primary Response arising from HP turbine)</td>
<td>%</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP turbine response ratio: (Proportion of High Frequency Response arising from HP turbine)</td>
<td>%</td>
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<td>DPD II</td>
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<td>End of Option 1</td>
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<tr>
<td>Option 2</td>
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<tr>
<td>All Generating Units and Synchronous Power Generating Units</td>
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</tr>
<tr>
<td>Governor Block Diagram showing transfer function of individual elements including acceleration sensitive elements</td>
<td></td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Governor Time Constant</td>
<td>Sec</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td><em>(PC.A.5.3.2(d) – Option 2(ii))</em> #Governor Deadband</td>
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<tr>
<td>- Maximum Setting</td>
<td>±Hz</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>- Normal Setting</td>
<td>±Hz</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>- Minimum Setting</td>
<td>±Hz</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Speeder Motor Setting Range</td>
<td>%</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td><em>(PC.A.5.3.2(d) – Option 2(ii))</em></td>
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</tr>
<tr>
<td>Average Gain <em>(PC.A.5.3.2(d) – Option 2(ii))</em></td>
<td>MW/Hz</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Steam Units <em>(PC.A.5.3.2(d) – Option 2(ii))</em></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>HP Valve Time Constant</td>
<td>sec</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP Valve Opening Limits</td>
<td>%</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP Valve Opening Rate Limits</td>
<td>%/sec</td>
<td></td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>HP Valve Closing Rate Limits</td>
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# 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.
## 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

### PAGE 9 OF 19

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**End of Option 2**

### UNIT CONTROL OPTIONS* *(PC.A.5.3.2(e))*

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<tr>
<td>Minimum droop</td>
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**Maximum Governor Deadband**

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**Normal Governor Deadband**

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**Minimum Governor Deadband**

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**Maximum Frequency Response Deadband**

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**Normal Frequency Response Deadband**

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**Minimum Frequency Response Deadband**

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**Maximum Frequency Response Insensitivity**

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**Normal Frequency Response Insensitivity**

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**Minimum Frequency Response Insensitivity**

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1 Data required only in respect of **Large Power Stations** comprising **Type C and Type D Power Generating Modules** owned and operated by **EU Code Generators**.
### 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

#### PAGE 10 OF 19

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<thead>
<tr>
<th>DATA DESCRIPTION</th>
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<th>DATA to RTL</th>
<th>DATA CAT.</th>
<th>POWER PARK UNIT (OR POWER PARK MODULE, AS THE CASE MAY BE)</th>
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<td>□ □ SPD+</td>
<td>G1 G2 G3 G4 G5 G6 STN</td>
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<td>□</td>
<td>□ □ SPD+</td>
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<td>(PC.A.3.3.1(a))</td>
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<td>*Performance Chart of a Power Park Module at the connection point (PC.A.3.2.2(f)(ii))</td>
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<td>□ □ SPD</td>
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<td>In the case where an appropriate Manufacturer’s Data &amp; 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 markedthus # below.</td>
<td></td>
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### 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**

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<td>G1 G2 G3 G4 G5 G6 STN</td>
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<td>Equivalent inertia constant of the first mass (e.g. wind turbine rotor and blades) at rated speed (PC.A.5.4.2(b))</td>
<td>MW secs /MVA</td>
<td>□</td>
<td>SPD+</td>
</tr>
<tr>
<td>Equivalent inertia constant of the second mass (e.g. generator rotor) at minimum speed (PC.A.5.4.2(b))</td>
<td>MW secs /MVA</td>
<td>□</td>
<td>SPD+</td>
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<tr>
<td>Equivalent inertia constant of the second mass (e.g. generator rotor) at synchronous speed (PC.A.5.4.2(b))</td>
<td>MW secs /MVA</td>
<td>□</td>
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<tr>
<td>Equivalent inertia constant of the second mass (e.g. generator rotor) at rated speed (PC.A.5.4.2(b))</td>
<td>MW secs /MVA</td>
<td>□</td>
<td>SPD+</td>
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<tr>
<td>Equivalent shaft stiffness between the two masses (PC.A.5.4.2(b))</td>
<td>Nm / electrical radian</td>
<td>□</td>
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<td>DATA CAT.</td>
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<td>Minimum generator rotor speed (Doubly Fed Induction Generators) (PC.A.3.3.1(e))</td>
<td>RPM</td>
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<tr>
<td>Maximum generator rotor speed (Doubly Fed Induction Generators) (PC.A.3.3.1(e))</td>
<td>RPM</td>
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<td>■</td>
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<td>The optimum generator rotor speed versus wind speed (PC.A.5.4.2(b))</td>
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<tr>
<td>Power Converter Rating (Doubly Fed Induction Generators) (PC.A.5.4.2(b))</td>
<td>MVA</td>
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<tr>
<td>The rotor power coefficient (C_p) versus tip speed ratio (\lambda) curves</td>
<td>Diagram + tabular format</td>
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<tr>
<td># The electrical power output versus generator rotor speed for a range of wind</td>
<td>Diagram + tabular format</td>
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<tr>
<td>speed over the entire operating range of the Power Park Unit. (PC.A.5.4.2(b))</td>
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<tr>
<td>The blade angle versus wind speed curve (PC.A.5.4.2(b))</td>
<td>Diagram + tabular format</td>
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<tr>
<td>The electrical power output versus wind speed over the entire operating range</td>
<td>Diagram + tabular format</td>
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<tr>
<td>of the Power Park Unit. (PC.A.5.4.2(b))</td>
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<tr>
<td>Transfer function block diagram, parameters and description of the operation of</td>
<td>Diagram</td>
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<tr>
<td>the power electronic converter including fault ride through capability (where</td>
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<td>applicable). (PC.A.5.4.2(b))</td>
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<td>For a Power Park Unit consisting of a synchronous machine in combination with a</td>
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<td>back to back DC Converter or HVDC Converter, or for a Power Park Unit not</td>
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<tr>
<td>driven by a wind turbine, the data to be supplied shall be agreed with The</td>
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<tr>
<td>Company in accordance with PC.A.7. (PC.A.5.4.2(b))</td>
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<tr>
<td>Torque / Speed and blade angle control systems and parameters (PC.A.5.4.2(c))</td>
<td>Diagram □</td>
<td>DPD II</td>
<td>G1 G2 G3 G4 G5 G6 STN</td>
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<tr>
<td>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</td>
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<tr>
<td># Voltage/Reactive Power/Power Factor control system parameters (PC.A.5.4.2(d))</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td># 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.</td>
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<tr>
<td># Frequency control system parameters (PC.A.5.4.2(e))</td>
<td>Diagram □</td>
<td>DPD II</td>
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</tr>
<tr>
<td># 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.</td>
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<tr>
<td>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))</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td># Harmonic Assessment Information (PC.A.5.4.2(h)) (as defined in IEC 61400-21 (2001)) for each Power Park Unit:-</td>
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<tr>
<td># Flicker coefficient for continuous operation</td>
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<td>DPD I</td>
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<tr>
<td># Flicker step factor</td>
<td>□</td>
<td>DPD I</td>
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<tr>
<td># Number of switching operations in a 10 minute window</td>
<td>□</td>
<td>DPD I</td>
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<tr>
<td># Number of switching operations in a 2 hour window</td>
<td>□</td>
<td>DPD I</td>
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<tr>
<td># Voltage change factor</td>
<td>□</td>
<td>DPD I</td>
<td></td>
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<tr>
<td># Current Injection at each harmonic for each Power Park Unit and for each Power Park Module</td>
<td>Tabular format □</td>
<td>DPD I</td>
<td></td>
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</table>

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.
### HVDC System and DC Converter Station Technical Data

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>DATA to RTL</th>
<th>Data Category</th>
<th>DC Converter Station Data</th>
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<tr>
<td>(PC.A.4)</td>
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<td>CUSC Contact</td>
<td>CUSC App. Form</td>
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<td><strong>HVDC System and DC Converter Station Demands:</strong></td>
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<td>Demand supplied through Station</td>
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<tr>
<td>Transformers associated with the DC Converter Station and HVDC System</td>
<td>MW</td>
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<td>DPD II</td>
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<tr>
<td>[PC.A.4.1]</td>
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<tr>
<td>- Demand with all DC Converters and HVDC Converters within and HVDC System operating at Rated MW import.</td>
<td>MW</td>
<td>DPD II</td>
<td>DPD II</td>
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<tr>
<td>- Demand with all DC Converters and HVDC Converters within an HVDC System operating at Rated MW export.</td>
<td>MVAr</td>
<td>DPD II</td>
<td>DPD II</td>
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<tr>
<td>Additional Demand associated with the DC Converter Station or HVDC System supplied through the National Electricity Transmission System. [PC.A.4.1]</td>
<td>MW</td>
<td>DPD II</td>
<td>DPD II</td>
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<tr>
<td>- The maximum Demand that could occur.</td>
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<td>DPD II</td>
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<tr>
<td>- Demand at specified time of annual peak half hour of The Company</td>
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<td>DPD II</td>
<td>DPD II</td>
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<td>Demand at Annual ACS Conditions.</td>
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<td>DPD II</td>
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<td>- Demand at specified time of annual minimum half-hour of The Company Demand.</td>
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<td><strong>DC Converter Station and HVDC System Data</strong></td>
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<tr>
<td>Number of poles, i.e. number of DC Converters or HVDC Converters within the HVDC System</td>
<td>Diagram</td>
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<tr>
<td>Pole arrangement (e.g. monopole or bipole)</td>
<td>Diagram</td>
<td>SPD+</td>
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<tr>
<td>Details of each viable operating configuration</td>
<td>Diagram</td>
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<td>Configuration 4</td>
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<td>Configuration 5</td>
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<td>Configuration 6</td>
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<tr>
<td>Remote ac connection arrangement</td>
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<tr>
<th>Data Description</th>
<th>Cusc Contract</th>
<th>Cusc App. Form</th>
<th>Data Category</th>
<th>Operating Configuration</th>
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<td><strong>DC CONVERTER STATION AND HVDC SYSTEM DATA (PC.A.3.3.1d)</strong></td>
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<tr>
<td>DC Converter or HVDC Converter Type (e.g. current or Voltage source)</td>
<td>Text</td>
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<td>SPD</td>
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<tr>
<td>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</td>
<td>Text</td>
<td>□</td>
<td>SPD</td>
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<tr>
<td>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</td>
<td>Section Number</td>
<td>□</td>
<td>SPD</td>
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<tr>
<td>Rated MW import per pole [PC.A.3.3.1]</td>
<td>MW</td>
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<tr>
<td>Rated MW export per pole [PC.A.3.3.1]</td>
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<td>Operating Configuration</td>
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<td>Registered Import Capacity</td>
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<td>Maximum HVDC Active Power Transmission Capacity</td>
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<tr>
<td>Minimum Active Power Transmission Capacity</td>
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<td>Import MW available in excess of Registered Import Capacity and Maximum Active Power Transmission Capacity</td>
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<td>Export MW available in excess of Registered Capacity and Maximum Active Power Transmission Capacity</td>
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<td><strong>DC CONVERTER AND HVDC CONVERTER TRANSFORMER [PC.A.5.4.3.1]</strong></td>
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<td>Nominal secondary (converter-side) voltage(s)</td>
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<tr>
<td>Maximum tap</td>
<td>% on MVA</td>
<td>□</td>
<td>DPD II</td>
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<td>Minimum tap</td>
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<td><strong>DC NETWORK [PC.A.5.4.3.1 (c)]</strong></td>
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<td>Rated DC voltage per pole</td>
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<td>DPD II</td>
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<tr>
<td>Rated DC current per pole</td>
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<td>inductance and capacitance of all DC cables and/or DC lines. Details of any</td>
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<td>line reactors (including line reactor resistance), line capacitors, DC filters,</td>
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<td>earthing electrodes and other conductors that form part of the DC Network should</td>
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<td>be shown.</td>
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<td>**DC CONVERTER STATION AND HVDC SYSTEM AC HARMONIC FILTER AND REACTIVE</td>
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<td>COMPENSATION EQUIPMENT [PC.A.5.4.3.1 (d)]</td>
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<td>Total number of AC filter banks</td>
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<td>Diagram of filter connections</td>
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<td>Type of equipment (e.g. fixed or variable)</td>
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<tr>
<td>Capacitive rating; or</td>
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<tr>
<td>Inductive rating; or</td>
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<td>-------------</td>
<td>---------------</td>
<td>-------------------------</td>
</tr>
<tr>
<td></td>
<td></td>
<td>CUSC Contract</td>
<td>CUSC App. Form</td>
<td>1 2 3 4 5 6</td>
</tr>
</tbody>
</table>
### CONTROL SYSTEMS [PC.A.5.4.3.2]

<table>
<thead>
<tr>
<th>Details</th>
<th>Diagram</th>
<th>DPD II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rectifier mode control system, in block diagram form together with parameters showing transfer functions of individual elements.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Inverter mode control system, in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>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.)</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>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.)</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Any frequency and/or load control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>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.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>HVDC Converter unit models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>AC component models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>DC Grid models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Voltage and power controller and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Special control features if applicable (e.g., 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.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Multi terminal control, if applicable and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>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.</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter.</td>
<td>□</td>
<td>DPD II</td>
</tr>
</tbody>
</table>
### Data Description

<table>
<thead>
<tr>
<th>Units</th>
<th>Operating configuration</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 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

**PAGE 19 OF 19**

### Loading Parameters

**[PC.A.5.4.3.3]**

<table>
<thead>
<tr>
<th>Description</th>
<th>Units</th>
<th>Data Category</th>
<th>Operating configuration</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW Export</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>Maximum (emergency) loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>MW Import</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nominal loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>Maximum (emergency) loading rate</td>
<td>MW/s</td>
<td>DPD I</td>
<td></td>
</tr>
<tr>
<td>Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.</td>
<td>s</td>
<td>□</td>
<td>DPD II</td>
</tr>
<tr>
<td>Maximum recovery time, to 90% of pre-fault loading, following a transient DC Network fault.</td>
<td>s</td>
<td>□</td>
<td>DPD II</td>
</tr>
</tbody>
</table>

**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.
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: _________________________

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CAT.</th>
<th>GENSET OR STATION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>OUTPUT CAPABILITY</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(PC.A.3.2.2) Registered Capacity on a station and unit basis</td>
<td>MW</td>
<td>□</td>
<td>■</td>
<td>SPD</td>
</tr>
<tr>
<td>on a station and module basis in the case of a CCGT Module or Power Park Module at a Large Power Station</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>MW</td>
<td>□</td>
<td>■</td>
<td>SPD</td>
</tr>
<tr>
<td>Maximum Capacity on a Power Generating Module basis and Synchronous Generating Unit basis and Registered Capacity on a Power Station basis</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minimum Generation on a module basis in the case of a CCGT Module or Power Park Module at a Large Power Station</td>
<td>MW</td>
<td>□</td>
<td>■</td>
<td>SPD</td>
</tr>
<tr>
<td>Minimum Stable Operating Level on a module basis in the case of a Power Generating Module at a Large Power Station</td>
<td>MW</td>
<td>□</td>
<td>■</td>
<td>SPD</td>
</tr>
</tbody>
</table>

### REGIME UNAVAILABILITY

These data blocks are provided to allow fixed periods of unavailability to be registered.

**Expected Running Regime**. Is Power Station normally available for full output 24 hours per day, 7 days per week? If No please provide details of unavailability below.

**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

**SYNCHRONISING PARAMETERS**

OC2.4.2.1(a)
<table>
<thead>
<tr>
<th>Notice to Deviate from Zero (NDZ) after 48 hour Shutdown</th>
<th>Mins</th>
<th>OC2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Station Synchronising Intervals (SI) after 48 hour Shutdown</td>
<td>Mins</td>
<td>-</td>
</tr>
<tr>
<td>Synchronising Group (if applicable)</td>
<td>1 to 4</td>
<td>OC2</td>
</tr>
</tbody>
</table>

- - - - - - -
## SCHEDULE 2 - GENERATION PLANNING PARAMETERS

### PAGE 2 OF 3

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CAT.</th>
<th>GENSET OR STATION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>CUSC Contract</td>
<td>CUSC App. Form</td>
<td>G1</td>
</tr>
<tr>
<td>Synchronising Generation (SYG) after 48 hour Shutdown</td>
<td>MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PC.A.5.3.2(l) &amp; OC2.4.2.1(a)</td>
<td></td>
<td>DPD II &amp; OC2</td>
<td></td>
<td></td>
</tr>
<tr>
<td>De-Synchronising Intervals (Single value)</td>
<td>Mins</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC2.4.2.1(a)</td>
<td></td>
<td>OC2</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

### RUNNING AND SHUTDOWN PERIOD LIMITATIONS:

| Minimum Non Zero time (MNZT) after 48 hour Shutdown | OC2 |
| OC2.4.2.1(a) | |
| Minimum Zero time (MZT) | OC2 |
| OC2.4.2.1(a) | |
| Existing AGR Plant Flexibility Limit | OC2 |
| (Existing AGR Plant only) | |
| 80% Reactor Thermal Power (expressed as Gross-Net MW) | OC2 |
| (Existing AGR Plant only) | |
| Frequency Sensitive AGR Unit Limit | OC2 |
| (Frequency Sensitive AGR Units only) | |

### RUN-UP PARAMETERS

| Run-up rates (RUR) after 48 hour Shutdown: | |
| (See note 2 page 3) | |
| MW Level 1 (MWL1) | MW | | DPD II & OC2 | |
| | | | OC2 | |
| MW Level 2 (MWL2) | MW | | DPD II & OC2 | |
| | | | OC2 | |
| RUR from Synch. Gen to MWL1 | MW/Mins | | DPD II & OC2 | |
| | | | OC2 | |
| RUR from MWL1 to MWL2 | MW/Mins | | OC2 | |
| RUR from MWL2 to RC | MW/Mins | | OC2 | |

### Run-Down Rates (RDR):

| (Note that for DPD only a single value of run-down rate from Registered Capacity to de-synch is required) | |
| MWL2 | MW | | DPD II & OC2 | |
| | | | OC2 | |
| RDR from RC to MWL2 | MW/Min | | DPD II & OC2 | |
| | | | OC2 | |
| MWL1 | MW | | DPD II & OC2 | |
| | | | OC2 | |
| RDR from MWL2 to MWL1 | MW/Min | | DPD II & OC2 | |
| | | | OC2 | |
| RDR from MWL1 to de-synch | MW/Min | | DPD II & OC2 | |
| | | | OC2 | |
### SCHEDULE 2 - GENERATION PLANNING PARAMETERS

**PAGE 3 OF 3**

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL CUSC Contract</th>
<th>DATA CAT. CUSC App. Form</th>
<th>GENSET OR STATION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>REGULATION PARAMETERS</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC2.4.2.1(a) Regulating Range</td>
<td>MW</td>
<td>■</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Load rejection capability while still Synchronised and able to supply Load.</td>
<td>MW</td>
<td>■</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>GAS TURBINE LOADING PARAMETERS:</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>OC2.4.2.1(a) Fast loading</td>
<td>MW/Min</td>
<td>■</td>
<td>OC2</td>
<td></td>
</tr>
<tr>
<td>Slow loading</td>
<td>MW/Min</td>
<td>■</td>
<td>OC2</td>
<td></td>
</tr>
<tr>
<td>CCGT MODULE PLANNING MATRIX</td>
<td></td>
<td>OC2</td>
<td>(please attach)</td>
<td></td>
</tr>
<tr>
<td>POWER PARK MODULE PLANNING MATRIX</td>
<td></td>
<td>OC2</td>
<td>(please attach)</td>
<td></td>
</tr>
<tr>
<td>Power Park Module Active Power Output/Intermittent Power Source Curve (e.g., MW output / Wind speed)</td>
<td></td>
<td>OC2</td>
<td>(please attach)</td>
<td></td>
</tr>
</tbody>
</table>

**NOTES:**

1. To allow for different groups of Gensets within a Power Station (e.g., 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.
(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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>TIME COVERED</th>
<th>UPDATE TIME</th>
<th>DATA CAT</th>
<th>DATA to RTL</th>
</tr>
</thead>
</table>

**OUTPUT PROFILES**

In the case of **Large Power Stations** whose output may be expected to vary in a random manner (e.g., wind power) or to some other pattern (e.g., Tidal) sufficient information is required to enable an understanding of the possible profile.

<table>
<thead>
<tr>
<th></th>
<th>UNIT</th>
<th>TIME COVERED</th>
<th>UPDATE TIME</th>
<th>DATA CAT</th>
<th>DATA to RTL</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MW</td>
<td>F. yrs 1 - 7</td>
<td>Week 24</td>
<td>SPD</td>
<td></td>
</tr>
</tbody>
</table>

Notes: 1. The week numbers quoted in the Update Time column refer to standard weeks in the current year.
**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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>NORMAL VALUE</th>
<th>MW</th>
<th>DROOP%</th>
<th>RESPONSE CAPABILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>Unit 1</td>
<td>Unit 2</td>
</tr>
<tr>
<td>MLP1</td>
<td>Designed Minimum Operating Level or Minimum Regulating Level (for a CCGT Module or Power Park Module, or on a modular basis assuming all units are Synchronised)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP2</td>
<td>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)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP3</td>
<td>70% of Registered Capacity or Maximum Capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP4</td>
<td>80% of Registered Capacity or Maximum Capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP5</td>
<td>95% of Registered Capacity or Maximum Capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>MLP6</td>
<td>Registered Capacity or Maximum Capacity</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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 or ECC.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 and 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(e)(vii) and CC.6.3.7(e)(viii) or ECC.6.3.3.1.1(f) 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 or ECC.6.3.7.
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)

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>USERS SYSTEM LAYOUT (PC.A.2.2)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A Single Line Diagram showing all or part of the User’s System is required. This diagram shall include:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(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 110kV and greater,</td>
<td>CUSC Contract</td>
<td>□□</td>
<td>SPD</td>
</tr>
<tr>
<td>(b) all parts of the User’s System operating at a voltage of 50kV and greater, and in Scotland and Offshore greater than 30kV, or higher which can interconnect Connection Points, or split bus-bars at a single Connection Point,</td>
<td>CUSC App. Form</td>
<td>□□</td>
<td></td>
</tr>
<tr>
<td>(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,</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(d) all parts of the User’s System at a Transmission Site.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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 (i.e., 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 110kV and greater, circuit breakers and phasing arrangements shall be shown.</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### REACTIVE COMPENSATION (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 customer's Plant or Apparatus:

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA EXCH</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of equipment (e.g., fixed or variable)</td>
<td>Text</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Capacitive rating; or</td>
<td>MVAR</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Inductive rating; or</td>
<td>MVAR</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Operating range</td>
<td>MVAR</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Details of automatic control logic to enable operating characteristics to be determined</td>
<td>text and/or diagrams</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Point of connection to User's System (electrical location and system voltage)</td>
<td>Text</td>
<td>■</td>
<td>■</td>
</tr>
</tbody>
</table>

### SUBSTATION INFRASTRUCTURE (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:

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA EXCH</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated 3-phase rms short-circuit withstand current</td>
<td>kA</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Rated 1-phase rms short-circuit withstand current</td>
<td>kA</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Rated Duration of short-circuit withstand</td>
<td>s</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Rated rms continuous current</td>
<td>A</td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA EXCH</td>
<td>DATA CATEGORY</td>
</tr>
<tr>
<td>---------------------------------------------------------------------------------</td>
<td>-------</td>
<td>-----------</td>
<td>---------------</td>
</tr>
<tr>
<td>LUMPED SUSCEPTANCES (PC.A.2.3)</td>
<td></td>
<td>CUSC Contract</td>
<td>CUSC App. Form</td>
</tr>
<tr>
<td>Equivalent Lumped Susceptance required for all parts of the User’s Subtransmission System which are not included in the Single Line Diagram.</td>
<td></td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>This should not include:</td>
<td></td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>(a) Independently switched reactive compensation equipment identified above.</td>
<td></td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>(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).</td>
<td></td>
<td>■</td>
<td>■</td>
</tr>
<tr>
<td>Equivalent lumped shunt susceptance at nominal Frequency. % on 100 MVA</td>
<td></td>
<td>■</td>
<td>■</td>
</tr>
</tbody>
</table>
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)

<table>
<thead>
<tr>
<th>Years Valid</th>
<th>Node 1</th>
<th>Node 2</th>
<th>Rated Voltage kV</th>
<th>Operating Voltage kV</th>
<th>Positive Phase Sequence % on 100 MVA</th>
<th>Zero Phase Sequence (self) % on 100 MVA</th>
<th>Zero Phase Sequence (mutual) % on 100 MVA</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>R</td>
<td>X</td>
<td>B</td>
<td>R</td>
<td>X</td>
<td>B</td>
<td>R</td>
</tr>
</tbody>
</table>

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.
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)**

<table>
<thead>
<tr>
<th>Years valid</th>
<th>Name of Node or Connection</th>
<th>Transformer</th>
<th>Rating MVA</th>
<th>Voltage Ratio</th>
<th>HV</th>
<th>LV</th>
<th>Positive Phase Sequence Reactance % on Rating</th>
<th>Positive Phase Sequence Resistance % on Rating</th>
<th>Zero Sequence Reactance % on Rating</th>
<th>Winding Arr.</th>
<th>Tap Changer Type</th>
<th>Earthing Details (delete as app.)</th>
<th>Range + % to - %</th>
<th>Step Size</th>
<th>Type (delete)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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<td></td>
<td></td>
<td>Direct/Res/Rea</td>
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<td></td>
<td>Direct/Res/Rea</td>
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<td></td>
<td></td>
<td>Direct/Res/Rea</td>
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<td>Direct/Res/Rea</td>
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<td>Direct/Res/Rea</td>
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<td>Direct/Res/Rea</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td>Direct/Res/Rea</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*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 (i.e., 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)

<table>
<thead>
<tr>
<th>Years Valid</th>
<th>Connect-ion Point</th>
<th>Switch No.</th>
<th>Rated Voltage kV rms</th>
<th>Operating Voltage kV rms</th>
<th>Rated short-circuit breaking current</th>
<th>Rated short-circuit peak making current</th>
<th>Rated rms continuous current (A)</th>
<th>DC time constant at testing of asymmetrical breaking ability(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3 Phase kA rms</td>
<td>1 Phase kA rms</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>3 Phase kA peak</td>
<td>1 Phase kA peak</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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)

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PROTECTION SYSTEMS</strong> <em>(PC.A.6.3)</em></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) A full description, including estimated settings, for all relays and Protection systems installed or to be installed on the User's System;</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(b) A full description of any auto-reclose facilities installed or to be installed on the User's System, including type and time delays;</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(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;</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(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.</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(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.</td>
<td>mSec</td>
<td></td>
<td>DPD II</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>POWER PARK MODULE/UNIT PROTECTION SYSTEMS</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Details of settings for the Power Park Module/Unit protection relays (to include): <em>(PC.A.5.4.2(f))</em></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(a) Under frequency,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(b) Over Frequency,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(c) Under Voltage, Over Voltage,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(d) Rotor Over current,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(e) Stator Over current,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(f) High Wind Speed Shut Down Level,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(g) Rotor Underspeed,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
<tr>
<td>(h) Rotor Overspeed,</td>
<td></td>
<td></td>
<td>DPD II</td>
</tr>
</tbody>
</table>
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 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 greater than 110kV: 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.

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 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
SCHEDULE 5 – USERS SYSTEM DATA
PAGE 9 OF 11

(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, e.g., 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 (e.g., 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) \textit{(PC.A.6.6 \textbullet\ 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 \( \pi \) 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)
<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>TIMESCALE COVERED</th>
<th>UPDATE TIME</th>
<th>DATA CAT.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Details are required from <strong>Network Operators</strong> of proposed outages in their <strong>User Systems</strong> and from <strong>Generators</strong> with respect to their outages, which may affect the performance of the <strong>Total System</strong> (e.g., at a <strong>Connection Point</strong> or constraining <strong>Embedded Large Power Stations</strong> or constraints to the <strong>Maximum Import Capacity</strong> or <strong>Maximum Export Capacity</strong> at an <strong>Interface Point</strong>) (OC2.4.1.3.2(a) &amp; (b))</td>
<td>CUSC Contract</td>
<td>CUSC App. Form</td>
<td>Years 2-5</td>
<td>Week 8 (Network Operator etc)</td>
<td>OC2</td>
</tr>
<tr>
<td>(The Company advises <strong>Network Operators</strong> of <strong>National Electricity Transmission System</strong> outages affecting their <strong>Systems</strong>)</td>
<td></td>
<td></td>
<td></td>
<td>Week 13 (Generators)</td>
<td>OC2</td>
</tr>
<tr>
<td><strong>Network Operator</strong>, informs <strong>The Company</strong> if unhappy with proposed outages</td>
<td></td>
<td></td>
<td>Years 2-5</td>
<td>Week 28</td>
<td>OC2</td>
</tr>
<tr>
<td>(The Company draws up revised <strong>National Electricity Transmission System</strong> (outage plan advises <strong>Users</strong> of operational effects)</td>
<td></td>
<td></td>
<td></td>
<td>Week 30</td>
<td>OC2</td>
</tr>
<tr>
<td><strong>Generators</strong> and <strong>Non-Embedded Customers</strong> provide Details of <strong>Apparatus</strong> owned by them (other than <strong>Gensets</strong>) at each <strong>Grid Supply Point</strong> (OC2.4.1.3.3)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 34</td>
<td>OC2</td>
</tr>
<tr>
<td>(The Company advises <strong>Network Operators</strong> of outages affecting their <strong>Systems</strong>) (OC2.4.1.3.3)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 28</td>
<td>OC2</td>
</tr>
<tr>
<td><strong>Network Operator</strong> details of relevant outages affecting the <strong>Total System</strong> (OC2.4.1.3.3)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 32</td>
<td>OC2</td>
</tr>
<tr>
<td>Details of:-</td>
<td>MVA / MW</td>
<td>MVA / MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Import Capacity</strong> for each <strong>Interface Point</strong></td>
<td></td>
<td>Year 1</td>
<td>Week 32</td>
<td>OC2</td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Export Capacity</strong> for each <strong>Interface Point</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Changes to previously declared values of the <strong>Interface Point Target Voltage/Power Factor</strong> (OC2.4.1.3.3(c)).</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(The Company informs <strong>Users</strong> of aspects that may affect their <strong>Systems</strong>) (OC2.4.1.3.3)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 34</td>
<td>OC2</td>
</tr>
<tr>
<td><strong>Users</strong> inform <strong>The Company</strong> if unhappy with aspects as notified (OC2.4.1.3.3)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 36</td>
<td>OC2</td>
</tr>
<tr>
<td>(The Company issues final <strong>National Electricity Transmission System</strong> (outage plan with advice of operational) (OC2.4.1.3.3) (effects on <strong>Users System</strong>)</td>
<td></td>
<td></td>
<td>Year 1</td>
<td>Week 49</td>
<td>OC2</td>
</tr>
<tr>
<td><strong>Generator, Network Operator and Non-Embedded Customers</strong> to inform <strong>The Company</strong> of changes to outages previously requested</td>
<td></td>
<td></td>
<td></td>
<td>Week 8 ahead to year end</td>
<td>OC2</td>
</tr>
<tr>
<td>Details of load transfer capability of 12MW or more between <strong>Grid Supply Points</strong> in England and Wales and 10MW or more between <strong>Grid Supply Points</strong> in Scotland.</td>
<td>MVA / MW</td>
<td></td>
<td>Within Yr 0</td>
<td>As occurring</td>
<td>OC2</td>
</tr>
<tr>
<td>Details of:-</td>
<td>MVA / MW</td>
<td>MVA / MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Import Capacity</strong> for each <strong>Interface Point</strong></td>
<td></td>
<td>Within Yr 0</td>
<td>As occurring</td>
<td>OC2</td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Export Capacity</strong> for each <strong>Interface Point</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Changes to previously declared values of the <strong>Interface Point Target Voltage/Power Factor</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>
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 applicable Retained EU Law (Commission Regulation (EU) 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.

<table>
<thead>
<tr>
<th>ECR ARTICLE No.</th>
<th>DATA DESCRIPTION</th>
<th>USERS PROVIDING DATA</th>
<th>FREQUENCY OF SUBMISSION</th>
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</thead>
<tbody>
<tr>
<td>7.1(a)</td>
<td>Planned unavailability of the Apparatus belonging to a Non-Embedded Customer where OC2.4.7 (a) applies</td>
<td>Non-Embedded Customer</td>
<td>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</td>
</tr>
</tbody>
</table>
|                 | - 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 |
| 7.1(b)          | Changes in actual availability of the Apparatus belonging to a Non-Embedded Customer where OC2.4.7 (b) applies | 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 |
|                 | - 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 |
| 8.1             | Year Ahead Forecast Margin information as provided in accordance with OC2.4.1.2.2 | Generator | In accordance with OC2.4.1.2.2 |
|                 | - Output Usable |
| 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 | Generator | Week 24 |
|                 | - Registered Capacity or Maximum Capacity (MW)  
|                 | - Production type (from that listed under PC.A.3.4.3) |
| 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 | Generator | Week 24 |
|                 | - Power Station name  
|                 | - Location of Generating Unit  
|                 | - Production type (from that listed under PC.A.3.4.3)  
|                 | - Voltage connection levels  
<p>|                 | - Registered Capacity or Maximum Capacity (MW) |
| 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 | Generator | In accordance with BC1.4.2 |
|                 | - Physical Notification |</p>
<table>
<thead>
<tr>
<th>Section</th>
<th>Description</th>
<th>Requirements</th>
</tr>
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<tr>
<td>15.1(a)</td>
<td>Planned unavailability of a Generating Unit where OC2.4.7(c) applies</td>
<td>To be received by The Generator 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</td>
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<tr>
<td>15.1(b)</td>
<td>Changes in availability of a Generating Unit and/or Power Generating Module where OC2.4.7 (d) applies</td>
<td>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</td>
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<tr>
<td>15.1(c)</td>
<td>Planned unavailability of a Power Station where OC2.4.7(e) applies</td>
<td>To be received by The Generator 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</td>
</tr>
<tr>
<td>15.1(d)</td>
<td>Changes in actual availability of a Power Station where OC2.4.7 (f) applies</td>
<td>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</td>
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</tbody>
</table>
### SCHEDULE 7 - LOAD CHARACTERISTICS AT GRID SUPPLY POINTS

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**.

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<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA TO RTL</th>
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<tbody>
<tr>
<td>FOR ALL TYPES OF DEMAND FOR EACH GRID SUPPLY POINT</td>
<td></td>
<td>CUSC Contract CUSC App Form</td>
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</table>

- 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))

- 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 □
  - Voltage Sensitivity (PC.A.4.7(b)) MVAr/kV □
  - Frequency Sensitivity (PC.A.4.7(b)) MW/Hz □
  - Frequency Sensitivity (PC.A.4.7(b)) 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)) □
<table>
<thead>
<tr>
<th>CODE</th>
<th>DESCRIPTION</th>
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<tbody>
<tr>
<td>BC1</td>
<td>Physical Notifications</td>
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<tr>
<td>BC1 &amp; BC2</td>
<td>Export and Import Limits</td>
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<tr>
<td>BC1</td>
<td>Bid-Offer Data</td>
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<td>BC1</td>
<td>Dynamic Parameters (Day Ahead)</td>
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<tr>
<td>BC2</td>
<td>Dynamic Parameters (For use in Balancing Mechanism)</td>
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<tr>
<td>BC1 &amp; BC2</td>
<td>Other Relevant Data</td>
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</tbody>
</table>

- 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)

<table>
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<tr>
<th>CODE</th>
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<tbody>
<tr>
<td>CC or ECC</td>
<td>Operation Diagram</td>
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<tr>
<td>CC or ECC</td>
<td>Site Responsibility Schedules</td>
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<td>PC</td>
<td>Day of the peak National Electricity Transmission System Demand</td>
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<tr>
<td>PC</td>
<td>Day of the minimum National Electricity Transmission System Demand</td>
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<tr>
<td>OC2</td>
<td>Surpluses and Output Useable (OU) requirements for each Generator over varying timescales</td>
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<td>Equivalent networks to Users for Outage Planning</td>
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<td>Negative Reserve Active Power Margins (when necessary)</td>
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<td>Operating Reserve information</td>
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<tr>
<td>BC1</td>
<td>Demand Estimates, Indicated Margin and Indicated Imbalance, indicative Synchronising and Desynchronising times of Embedded Power Stations to Network Operators, special actions.</td>
</tr>
<tr>
<td>BC2</td>
<td>Bid-Offer Acceptances, Ancillary Services instructions to relevant Users, Emergency Instructions</td>
</tr>
<tr>
<td>BC3</td>
<td>Location, amount, and Low Frequency Relay settings of any Low Frequency Relay initiated Demand reduction for Demand which is Embedded.</td>
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</tbody>
</table>

- 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 a 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.
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).

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<th>F. Yr. 4</th>
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<th>F. Yr. 7</th>
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<td><strong>Demand Profiles</strong></td>
<td>(PC.A.4.2) [■ - CUSC Contract &amp; ■ CUSC Application Form]</td>
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<td></td>
<td></td>
</tr>
</tbody>
</table>
### DATA DESCRIPTION

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>Out-turn Actual Weather Corrected.</th>
<th>F.Yr. 0 Update Time</th>
<th>Data Cat</th>
<th>DATA to RTL</th>
</tr>
</thead>
<tbody>
<tr>
<td>(PC.A.4.3)</td>
<td></td>
<td>Week 24</td>
<td>SPD</td>
<td></td>
</tr>
<tr>
<td><strong>Active Energy Data</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total annual Active Energy requirements under average conditions of each Network Operator and each Non-Embedded Customer in the following categories of Customer Tariff:-</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LV1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LV2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>LV3</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EHV</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>HV</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Traction</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Lighting</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>User System Losses</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Active Energy from Embedded Small Power Stations and Embedded Medium Power Stations</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 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.
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:**

<table>
<thead>
<tr>
<th>Connection Point Demand at the time of - (select each one in turn) (Provide data for each Access Period associated with the Connection Point)</th>
</tr>
</thead>
<tbody>
<tr>
<td>a) maximum Demand at the time of -</td>
</tr>
<tr>
<td>b) peak National Electricity Transmission System Demand (specified by The Company)</td>
</tr>
<tr>
<td>c) minimum National Electricity Transmission System Demand (specified by The Company)</td>
</tr>
<tr>
<td>d) maximum Demand during Access Period</td>
</tr>
<tr>
<td>e) specified by either The Company or a User</td>
</tr>
</tbody>
</table>

**Name of Transmission Interface Circuit out of service during Access Period (if reqd).**

<table>
<thead>
<tr>
<th>Name of Transmission Interface Circuit out of service during Access Period (if reqd).</th>
</tr>
</thead>
<tbody>
<tr>
<td>PC.A.4.1.4.2</td>
</tr>
</tbody>
</table>

### DATA DESCRIPTION

(CUSC Contract □ & CUSC Application Form ■)

<table>
<thead>
<tr>
<th>Outturn Weather Corrected</th>
<th>F.Yr 1</th>
<th>F.Yr 2</th>
<th>F.Yr 3</th>
<th>F.Yr 4</th>
<th>F.Yr 5</th>
<th>F.Yr 6</th>
<th>F.Yr 7</th>
<th>F.Yr 8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date of a), b), c), d) or e) as denoted above.</td>
<td>PC.A.4.3.3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time of a), b), c), d) or e) as denoted above.</td>
<td>PC.A.4.3.3</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connection Point Demand (MW)</td>
<td>PC.A.4.3.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Connection Point Demand (MVAr)</td>
<td>PC.A.4.3.1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Deduction made at Connection Point for Small Power Stations, Medium Power Stations and Customer Generating Plant (MW)</td>
<td>PC.A.4.3.2(a)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference to valid Single Line Diagram</td>
<td>PC.A.4.3.5</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference to node and branch data.</td>
<td>PC.A.2.2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**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) |
## Embedded Generation Data

<table>
<thead>
<tr>
<th>Connection Point</th>
<th>Data Description</th>
<th>Outturn Weather Corrected</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>F.Yr</th>
<th>Data CAT</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Power Station, Medium Power Station and Customer Generation Summary</td>
<td>For each Connection Point where there are Embedded Small Power Stations, Medium Power Stations or Customer Generating Stations the following information is required:</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No. of Small Power Stations, Medium Power Stations or Customer Power Stations</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.1 .4(a)</td>
<td></td>
</tr>
<tr>
<td>Number of Generating Units within these stations</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.1 .4(a)</td>
<td></td>
</tr>
<tr>
<td>Summated Capacity of all these Generating Units</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.1 .4(a)</td>
<td></td>
</tr>
</tbody>
</table>

Where the Network Operator's System places a constraint on the capacity of an Embedded Large Power Station

<table>
<thead>
<tr>
<th>Station Name</th>
<th>Generating Unit</th>
<th>System Constrained Capacity</th>
<th>Reactive Despatch Network Restriction</th>
<th>Data CAT</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.2 .2(c)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.2 .2(c)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.2 .2(c)(i)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>PC.A.3.2 .2(c)(ii)</td>
</tr>
</tbody>
</table>
Where the *Network Operator's System* places a constraint on the capacity of an *Offshore Transmission System* at an *Interface Point*

<table>
<thead>
<tr>
<th>Offshore Transmission System Name</th>
<th></th>
<th>PC.A.3.2. 2(c)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interface Point Name</td>
<td></td>
<td>PC.A.3.2. 2(c)</td>
</tr>
<tr>
<td>Maximum Export Capacity</td>
<td></td>
<td>PC.A.3.2. 2(c)</td>
</tr>
<tr>
<td>Maximum Import Capacity</td>
<td></td>
<td>PC.A.3.2. 2(c)</td>
</tr>
</tbody>
</table>

**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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>An Embedded Small Power Station reference unique to each Network Operator</th>
<th>Connection Date (Financial Year for generator connecting after week 24 2015)</th>
<th>Generator unit Reference</th>
<th>Technology Type / Production type</th>
<th>CHP (Y/N)</th>
<th>Registered capacity in MW (as defined in the Distribution Code)</th>
<th>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</th>
<th>Where it exports electricity from wind PV or storage, the geographical location of the primary or higher voltage substation to which it connects</th>
<th>Control mode</th>
<th>Control mode voltage target and reactive range or target pf (as appropriate)</th>
<th>Loss of mains protection type</th>
<th>Loss of mains protection settings</th>
</tr>
</thead>
<tbody>
<tr>
<td>DATA CAT</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td>PC.A.3.1.4 (a)</td>
<td></td>
</tr>
</tbody>
</table>
NOTES:

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, Embedded 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, Embedded 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 (e.g. wind power) or according to some other pattern (e.g. 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.
### Embedded Small Power Stations <1MW

<table>
<thead>
<tr>
<th>Fuel Type</th>
<th>Aggregate Registered Capacity</th>
<th>Number of PGMs</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil brown coal/lignite</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil coal-derived gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil gas</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil hard coal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil oil</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil oil shale</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fossil peat</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Geothermal</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro pumped storage</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro run-of-river and poundage</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro water reservoir</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marine</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other renewable</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Waste</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind offshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind onshore</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Other</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
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** and **Generators** in respect of **Electricity Storage Modules**. Where indicated with a double asterisk, the information is only required from **Suppliers**.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>UPDATE TIME</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Demand Control</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Control at time of National Electricity Transmission System weekly peak demand</td>
<td>MW</td>
<td>F.yrs 0 to 5</td>
</tr>
<tr>
<td>Amount</td>
<td>Min</td>
<td>)</td>
</tr>
<tr>
<td>For each half hour</td>
<td>MW</td>
<td>Wks 2-8 ahead</td>
</tr>
<tr>
<td>For each half hour</td>
<td>MW</td>
<td>Days 2-12 ahead</td>
</tr>
<tr>
<td>For each half hour</td>
<td>MW</td>
<td>Previous calendar day</td>
</tr>
<tr>
<td><strong>Customer Demand Management</strong> (at the Customer Demand Management Notification Level or more at the Connection Point)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>For each half hour</td>
<td>MW</td>
<td>Any time in Control Phase</td>
</tr>
<tr>
<td>For each half hour</td>
<td>MW</td>
<td>Remainder of period</td>
</tr>
<tr>
<td><strong>In Scotland, Load Management Blocks</strong> For each block of 5MW or more, for each half hour</td>
<td>MW</td>
<td>Previous calendar day For the next day</td>
</tr>
<tr>
<td><strong>In Scotland, Load Management Blocks</strong> For each block of 5MW or more, for each half hour</td>
<td>MW</td>
<td>For the next day 11:00 OC1</td>
</tr>
</tbody>
</table>
SCHEDULE 12 - DEMAND CONTROL
PAGE 2 OF 2

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>TIME COVERED</th>
<th>UPDATE TIME</th>
<th>DATA CAT.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand Control or Pump Tripping Offered as Reserve</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Magnitude of Demand or pumping load or Electricity Storage charging load which is tripped</td>
<td>MW</td>
<td>Year ahead from week 24</td>
<td>Week 24</td>
<td>DPD I</td>
</tr>
<tr>
<td>System Frequency at which tripping is initiated</td>
<td>Hz</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Time duration of System Frequency below trip setting for tripping to be initiated</td>
<td>S</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Time delay from trip initiation to Tripping</td>
<td>S</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Electricity Storage Module data</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Capacity</td>
<td>MW</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Maximum Import Power</td>
<td>MW</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Registered Import Capability</td>
<td>MW</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Charge Time</td>
<td>Min</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Discharge time</td>
<td>Min</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Operating periods</td>
<td>Min</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Emergency Manual Load Disconnection</td>
<td>Text</td>
<td>Year ahead from week 24</td>
<td>Annual in week 24</td>
<td>OC6</td>
</tr>
<tr>
<td>Annual ACS Peak Demand (Active Power) at Connection Point (requested under Schedule 11 - repeated here for reference)</td>
<td>MW</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>Cumulative percentage of Connection Point Demand (Active Power) which can be disconnected by the following times from an instruction from The Company</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>10 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>15 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>20 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>25 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
<tr>
<td>30 mins</td>
<td>%</td>
<td>&quot;</td>
<td>&quot;</td>
<td>&quot;</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Grid Supply Point</th>
<th>GSP Demand MW</th>
<th>Low Frequency Demand Disconnection Blocks MW</th>
<th>Residual Demand MW</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
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#### Grid Supply Points

- GSP1
- GSP2
- GSP3

**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).
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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>F.Yr 0</th>
<th>F.Yr 1</th>
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<th>F.Yr 4</th>
<th>F.Yr 5</th>
<th>F.Yr 6</th>
<th>F.Yr 7</th>
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<td></td>
<td>CUSC Contract</td>
<td>CUSC App. Form</td>
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<tr>
<td>Symmetrical three phase short-circuit current infeed</td>
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<td>- at instant of fault</td>
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<tr>
<td>- after subtransient fault current contribution has substantially decayed</td>
<td>Ka</td>
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<td>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:</td>
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<td>- Resistance</td>
<td>% on 100</td>
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<td>- Reactance</td>
<td>% on 100</td>
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<tr>
<td>Positive sequence X/R ratio at instance of fault</td>
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<td>Pre-Fault voltage magnitude at which the maximum fault currents were calculated</td>
<td>p.u.</td>
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## SCHEDULE 13 - FAULT INFEED DATA
### PAGE 2 OF 2

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<th>DATA DESCRIPTION</th>
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<th>F.Yr. 3</th>
<th>F.Yr. 4</th>
<th>F.Yr. 5</th>
<th>F.Yr. 6</th>
<th>F.Yr. 7</th>
<th>DATA to RTL</th>
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<td>CUSC Contract</td>
<td>CUSC App. Form</td>
</tr>
<tr>
<td>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.</td>
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<td>- Resistance % on 100</td>
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<td>- Reactance % on 100</td>
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</table>
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.

**Fault infeeds via Unit Transformers**

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 (e.g. 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

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<th>F.Yr. 3</th>
<th>F.Yr. 4</th>
<th>F.Yr. 5</th>
<th>F.Yr. 6</th>
<th>F.Yr. 7</th>
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<td>CUSC Contract</td>
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<td>Number of Unit Transformers</td>
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<tr>
<td>Symmetrical three phase short-circuit current infeed through the Unit Transformers(s) for a fault at the Generating Unit terminals</td>
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<td>- at instant of fault</td>
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<tr>
<td>- after subtransient fault current contribution has substantially decayed</td>
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<td>Subtransient time constant (if significantly different from 40ms)</td>
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<tr>
<td>Pre-fault voltage at fault point (if different from 1.0 p.u.)</td>
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<tr>
<td>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</td>
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<tr>
<td>Zero sequence source impedances as seen from the Generating Unit terminals consistent with the maximum infeed above:</td>
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<td>- Resistance</td>
<td>% on 100</td>
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<tr>
<td>- Reactance</td>
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</table>
Fault infeeds via Station Transformers

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 (e.g. **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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>F.Yr. 0</th>
<th>F.Yr. 1</th>
<th>F.Yr. 2</th>
<th>F.Yr. 3</th>
<th>F.Yr. 4</th>
<th>F.Yr. 5</th>
<th>F.Yr. 6</th>
<th>F.Yr. 7</th>
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<tr>
<td>Symmetrical three phase short-circuit current infeed for a fault at the Connection Point</td>
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<td>- at instant of fault</td>
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<tr>
<td>- after subtransient fault current contribution has substantially decayed</td>
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<td>Positive sequence X/R ratio</td>
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<td>At instance of fault</td>
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<td>Subtransient time constant (if significantly different from 40ms)</td>
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<tr>
<td>Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)</td>
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<tr>
<td>Zero sequence source Impedances as seen from the Point of Connection Consistent with the maximum Infeed above:</td>
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<td>- Resistance</td>
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<td>- Reactance</td>
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</table>

**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
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

<table>
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<th>F.Yr. 6</th>
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</table>

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

<table>
<thead>
<tr>
<th>Data Description</th>
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<th>F.Yr.</th>
<th>F.Yr.</th>
<th>F.Yr.</th>
<th>F.Yr.</th>
<th>Data to RTL</th>
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</thead>
<tbody>
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<td>A continuous time trace and table showing the root mean square of the positive,</td>
<td>Graphical and tabular kA versus s</td>
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<tr>
<td>negative and zero sequence components of the fault current from the time of fault</td>
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<td>inception to 140ms after fault inception at 10ms intervals</td>
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<tr>
<td>A continuous time trace and table showing the positive, negative and zero</td>
<td>Pu versus s</td>
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<tr>
<td>sequence components of retained voltage at the terminals or Common Collection</td>
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<tr>
<td>Busbar, if appropriate</td>
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<tr>
<td>A continuous time trace and table showing the root mean square of the positive,</td>
<td>Pu versus s</td>
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<td>negative and zero sequence components of retained voltage at the fault point, if</td>
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</table>

CUSC Contract  CUSC App. Form
## SCHEDULE 14 - FAULT INFEED DATA (GENERATORS INCLUDING UNIT TRANSFORMERS AND STATION TRANSFORMERS)

PAGE 5 OF 5

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>F.Yr. 0</th>
<th>F.Yr. 1</th>
<th>F.Yr. 2</th>
<th>F.Yr. 3</th>
<th>F.Yr. 4</th>
<th>F.Yr. 5</th>
<th>F.Yr. 6</th>
<th>F.Yr. 7</th>
<th>DATA to RTL</th>
</tr>
</thead>
<tbody>
<tr>
<td>For Power Park Units that utilise a protective control, such as a crowbar circuit,</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>- additional rotor resistance applied to the Power Park Unit under a fault situation</td>
<td>% on</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>- additional rotor reactance applied to the Power Park Unit under a fault situation</td>
<td>% on</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
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</tr>
<tr>
<td>Positive sequence X/R ratio of the equivalent at time of fault at the Common Collection Busbar</td>
<td></td>
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</tr>
<tr>
<td>Minimum zero sequence impedance of the equivalent at a Common Collection Busbar</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
<td></td>
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</tr>
<tr>
<td>Active Power generated pre-fault</td>
<td>MW</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Number of Power Park Units in equivalent generator</td>
<td></td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Power Factor (lead or lag)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pre-fault voltage (if different from 1.0 pu) at fault point (See note 1)</td>
<td>pu</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Items of reactive compensation switched in pre-fault</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

Note 1. The pre-fault voltage provided above should represent the voltage within the range 0.95 pu to 1.05 pu that gives the highest fault current.
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 and Alternative Fuel Data.

<table>
<thead>
<tr>
<th>Power Station Generating Unit, Power Park Module or DC Converter Name (e.g. Unit 1)</th>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA CAT</th>
<th>&lt;1 month</th>
<th>1-2 months</th>
<th>2-3 months</th>
<th>3-6 months</th>
<th>6-12 months</th>
<th>&gt;12 months</th>
<th>Total MW being returned</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW output that can be returned to service</td>
<td>MW</td>
<td>DPD II</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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 Module), 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.
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 those which form part of a Power Generating Module.

<table>
<thead>
<tr>
<th>Power Station</th>
<th>Generating Unit Name (e.g. Unit 1)</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA CAT</th>
<th>GENERATING UNIT DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alternative Fuel Type (*please specify)</td>
<td>Text</td>
<td>DPD II</td>
<td>Oil distillate</td>
</tr>
<tr>
<td>CHANGEOVER TO ALTERNATIVE FUEL</td>
<td>minutes</td>
<td>DPD II</td>
<td>minutes</td>
</tr>
<tr>
<td>For off-line changeover:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time to carry out off-line fuel changeover</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum output following on-line changeover</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum operating time at full load assuming:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Typical stock levels</td>
<td>hours</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Maximum possible stock levels</td>
<td>hours</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Maximum rate of replacement of depleted stocks of alternative fuels on the basis of Good Industry Practice</td>
<td>MWh(electrical)</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Is changeover to alternative fuel used in normal operating arrangements?</td>
<td>text</td>
<td>DPD II</td>
<td></td>
</tr>
<tr>
<td>Number of successful changeovers carried out in the last Financial Year (** delete as appropriate)</td>
<td>text</td>
<td>DPD II</td>
<td>0 / 1-5 / 6-10 / 11-20 / &gt;20 **</td>
</tr>
<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>DATA CAT</td>
<td>GENERATING UNIT DATA</td>
</tr>
<tr>
<td>------------------------------------------------------</td>
<td>-------</td>
<td>----------</td>
<td>---------------------</td>
</tr>
<tr>
<td>CHANGEOVER BACK TO MAIN FUEL</td>
<td></td>
<td></td>
<td>1   2   3    4</td>
</tr>
<tr>
<td>For off-line changeover:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time to carry out off-line fuel changeover</td>
<td>Minutes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>For on-line changeover:</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Time to carry out on-line fuel changeover</td>
<td>Minutes</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum output during on-line fuel changeover</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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.
**BLACK START INFORMATION**

The following data/text items are required for each BM Unit at a Large Power Station as detailed in P.C.A.5.7. Data is not required for Generating Units that are contracted to provide Black Start Capability, or Electricity Storage Modules which have short cycle times. The data should be provided in accordance with P.C.A.2 and also, where possible, upon request from The Company during a Black Start.

<table>
<thead>
<tr>
<th>Data Description (P.C.A.5.7)</th>
<th>Data Category</th>
<th>DPD II</th>
<th>DPD II</th>
<th>DPD II</th>
</tr>
</thead>
<tbody>
<tr>
<td>Units</td>
<td>Tabular or Graphical</td>
<td>Text</td>
<td>Tabular or Graphical</td>
<td></td>
</tr>
<tr>
<td>Black Start Information</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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.</td>
<td>Assumed 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.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>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 parking facilities, time from a Total Shutdown or Partial Shutdown at which batteries would be discharged.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>c) Provide estimated Block Loading Capacity from 0MW to Registered Capacity of each BM Unit based on the unit being hot (run prior to shutdown) and also could (not run for 48hrs or more prior to the shutdown). The Block Loading Capacity should be valid for a frequency deviation of 49.5Hz – 50.5Hz. The data should identify any required hold points.</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
## 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 PCA.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 PCA.1.2 and also, where possible, upon request from The Company during a Black Start.

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data Category</th>
</tr>
</thead>
<tbody>
<tr>
<td>(PCA.5.7) (CUSIC Contract)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

- **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.

### 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.
Submissions by Users using this Schedule 17 shall commence in 2011 and shall then continue in each year thereafter.

<table>
<thead>
<tr>
<th>Access Group</th>
<th>Asset Identifier</th>
<th>Start Week</th>
<th>End Week</th>
<th>Maintenance Year (1, 2 or 3)</th>
<th>Duration</th>
<th>Potential Concurrent Outage (Y/N)</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
</tbody>
</table>

Comments


The data in this Schedule 18 is required from Generators who are undertaking OTSDUW and connecting to a Transmission Interface Point.

### DATA DESCRIPTION

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CAT.</th>
<th>GENERATING UNIT OR STATION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>INDIVIDUAL OTSDUW DATA</strong></td>
<td></td>
<td></td>
<td></td>
<td>F.Yr0</td>
</tr>
<tr>
<td>Interface Point Capacity (PC.A.3.2.2 (a))</td>
<td>MW</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Performance Chart at the</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transmission Interface Point for OTSDUW Plant and Apparatus (PC.A.3.2.2(f)(iv)</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**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.  
  - Demand at specified time of annual peak half hour of National Electricity Transmission System Demand at Annual ACS Conditions.  
  - Demand at specified time of annual minimum half-hour of National Electricity Transmission System Demand.

(Note 1 – Demand required from OTSDUW DC Converters should be supplied under page 2 of Schedule 18).
### OTSDUW USERS SYSTEM DATA

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>DATA to RTL</th>
<th>DATA CATEGORY</th>
</tr>
</thead>
</table>
| **OFFSHORE TRANSMISSION SYSTEM LAYOUT**  
(PC.A.2.2.1, PC.A.2.2.2 and P.C.A.2.2.3) |       | CUSC Contract  
CUSC App. Form | SPD |
| 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 (i.e. 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 | ■  ■ | SPD |
| 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)

<table>
<thead>
<tr>
<th>Node 1</th>
<th>Node 2</th>
<th>Rated Voltage (kV)</th>
<th>Operating Voltage (kV)</th>
<th>Circuit</th>
<th>PPS PARAMETERS</th>
<th>ZPS PARAMETERS</th>
<th>Maximum Continuous Ratings</th>
<th>Length (km)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>R1 %100 MVA</td>
<td>X1 %100 MVA</td>
<td>R0 %100 MVA</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>B 1 %100 MVA</td>
<td>X0 %100M VA</td>
<td>B0 %100M VA</td>
<td>Winter (MVA)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Spring Autumn (MVA)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Summer (MVA)</td>
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<td></td>
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<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### 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.
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**.

<table>
<thead>
<tr>
<th>HV Node (kV)</th>
<th>HV Node</th>
<th>LV (kV)</th>
<th>LV (kV)</th>
<th>Rating (MVA)</th>
<th>Transformer</th>
<th>Positive Phase Sequence Reactance % on 100MVA</th>
<th>Positive Phase Sequence Resistance % on 100 MVA</th>
<th>Tap Changer</th>
<th>Winding Arr.</th>
<th>Earthing Method (Direct/Res./Reac.)</th>
<th>Earthing Impedance method</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Max Tap</td>
<td>Min Tap</td>
<td>Nom Tap</td>
<td>Max Tap</td>
<td>Min Tap</td>
<td>Nom Tap</td>
<td>Range +% to -%</td>
</tr>
</tbody>
</table>

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*.

<table>
<thead>
<tr>
<th>HV NODE</th>
<th>V_H (kV)</th>
<th>LV NODE</th>
<th>V_L (kV)</th>
<th>PSS/E Circuit</th>
<th>Rating (MVA)</th>
<th>Transformer</th>
<th>Positive Phase Sequence Resistance % on 100MVA</th>
<th>Positive Phase Sequence Reactance % on 100 MVA</th>
<th>Taps</th>
<th>Equivalent T ZPS Parameters (FLIP)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| Notes | 1. For information STC Reference: STCP12-1: Part 3 - 2.4 Transformers |
OFFSHORE TRANSMISSION SYSTEM DATA

Circuit Breaker Data (PC.A.2.2.6(a))

The data below is all **Standard Planning Data**, and should be provided for all OTSUA switchgear (i.e. circuit breakers, load disconnectors and disconnectors)

| 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) (kA) | Fault Break Rating (Peak Asymmetrical) (3 phase) (kA) | Fault Make Break Rating (Peak Asymmetrical) (3 phase) (kA) | Fault Break Rating (RMS Symmetrical) (1 phase) (kA) | Fault Break Rating (Peak Asymmetrical) (1 phase) (kA) | Fault Make Break Rating (Peak Asymmetrical) (1 phase) (kA) | DC time constant at testing of a symmetrical breaking ability (s) |
|----------|------|---------------|-------------------|------|-------|------|-----------------|-------------------|--------------------------------|----------------|----------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|-----------------------------------------------|

<table>
<thead>
<tr>
<th>Circuit Breaker Data</th>
<th>Assumed Operating Times</th>
<th>3 Phase</th>
<th>1 Phase</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
REACTIVE COMPENSATION EQUIPMENT (PC.A.2.4(e))

<table>
<thead>
<tr>
<th>Item</th>
<th>Node</th>
<th>kV</th>
<th>Device No.</th>
<th>Rating (MVAr)</th>
<th>P Loss (kW)</th>
<th>Tap range</th>
<th>Connection Arrangement</th>
</tr>
</thead>
</table>

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))**

<table>
<thead>
<tr>
<th>HV Node</th>
<th>LV Node</th>
<th>Control Node</th>
<th>Nominal Voltage (kV)</th>
<th>Target Voltage (kV)</th>
<th>Max MVAR at HV</th>
<th>Min MVAR at HV</th>
<th>Slope %</th>
<th>Voltage Dependant Q Limit</th>
<th>Normal Running Mode</th>
<th>R1 PPS_R</th>
<th>X1 PPS_X</th>
<th>R0 ZPS_R</th>
<th>X0 ZPS_X</th>
<th>Transf. Winding Type</th>
<th>Connection (Direct/Tertiary)</th>
</tr>
</thead>
<tbody>
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</tbody>
</table>

#### Notes:

1. For information the equivalent STC Reference is: STCP12-1: Part 3 - 2.7 SVC Modelling Data

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**SCHEDULE 18 - OFFSHORE TRANSMISSION SYSTEM DATA**

**PAGE 8 OF 24**
## Harmonic Filter Data

### Filter Description (including OTSUW DC Converter harmonic Filter Data)

*PC.A.5.4.3.1(d) and PC.A.6.4.2*

<table>
<thead>
<tr>
<th>Site Name</th>
<th>SLD Reference</th>
<th>Point of Filter Connection</th>
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<tbody>
<tr>
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</table>

<table>
<thead>
<tr>
<th>Manufacturer</th>
<th>Model</th>
<th>Filter Type</th>
<th>Filter connection type (Delta/Star, Grounded/ Ungrounded)</th>
<th>Notes</th>
</tr>
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<tbody>
<tr>
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<table>
<thead>
<tr>
<th>Bus Voltage</th>
<th>Rating</th>
<th>Q factor</th>
<th>Tuning Frequency</th>
<th>Notes</th>
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</thead>
<tbody>
<tr>
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</table>

### Component Parameters (as per SLD)

**Parameter as applicable**

<table>
<thead>
<tr>
<th>Filter Component (R, C or L)</th>
<th>Capacitance (micro-Farads)</th>
<th>Inductance (milli-Henrys)</th>
<th>Resistance (Ohms)</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
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</table>

### 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
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
SCHEDULE 18 - OFFSHORE TRANSMISSION SYSTEM DATA
PAGE 11 OF 24

(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

Voltage Assessment Studies (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 (e.g. 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.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>UNITS</th>
<th>F.Yr. 0</th>
<th>F.Yr. 1</th>
<th>F.Yr. 2</th>
<th>F.Yr. 3</th>
<th>F.Yr. 4</th>
<th>F.Yr. 5</th>
<th>F.Yr. 6</th>
<th>F.Yr. 7</th>
<th>DATA to RTL</th>
</tr>
</thead>
<tbody>
<tr>
<td>(PC.A.2.5)</td>
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<td>CUSC Contract</td>
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<tr>
<td>Name of OTSDUW Plant and Apparatus</td>
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<tr>
<td>OTSDUW DC Converter type (i.e. voltage or current source)</td>
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<tr>
<td>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</td>
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<tr>
<td>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.</td>
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<tr>
<td>DATA DESCRIPTION</td>
<td>UNITS</td>
<td>F. Yr. 0</td>
<td>F. Yr. 1</td>
<td>F. Yr. 2</td>
<td>F. Yr. 3</td>
<td>F. Yr. 4</td>
<td>F. Yr. 5</td>
<td>F. Yr. 6</td>
<td>F. Yr. 7</td>
<td>DATA to RTL</td>
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<tr>
<td>- 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</td>
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<td>CUSC Contract CUSC App. Form</td>
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<td>Graphical and tabular</td>
<td>kA versus s</td>
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<tr>
<td>- 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</td>
<td>p.u. versus s</td>
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<tr>
<td>- 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</td>
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<tr>
<td>Positive sequence X/R ratio of the equivalent at time of fault at the Interface Point and each Connection Point</td>
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<tr>
<td>Minimum zero sequence impedance of the equivalent at the Interface Point and each Connection Point</td>
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<tr>
<td>Active Power transfer at the Interface Point and each Connection Point pre-fault</td>
<td>MW</td>
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<tr>
<td>Power Factor (lead or lag)</td>
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<tr>
<td>Pre-fault voltage (if different from 1.0 p.u.) at fault point (See note 1)</td>
<td>p.u.</td>
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<tr>
<td>Items of reactive compensation switched in pre-fault</td>
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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

#### CIRCUIT RATING SCHEDULE

**Offshore TO Name**

**CIRCUIT Name from Site A – Site B**

| Voltage | 132kV |

#### Thermal Ratings Data (PC.A.2.2.4)

<table>
<thead>
<tr>
<th>OVERALL CCT RATINGS</th>
<th>Winter</th>
<th>Spring/Autumn</th>
<th>Summer</th>
</tr>
</thead>
<tbody>
<tr>
<td>%Nom</td>
<td>Limit</td>
<td>Amps</td>
<td>MVA</td>
</tr>
<tr>
<td>Pre-Fault Continuous</td>
<td>84%</td>
<td>485</td>
<td>111</td>
</tr>
<tr>
<td>Post-Fault Continuous</td>
<td>100%</td>
<td>580</td>
<td>132</td>
</tr>
<tr>
<td>Prefault load exceeds line prefault continuous rating</td>
<td></td>
<td></td>
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</tr>
<tr>
<td>6hr 95%</td>
<td>Line 580 132</td>
<td>95%</td>
<td>Line 540 123</td>
</tr>
<tr>
<td>20m 84%</td>
<td>Line 590 135</td>
<td>84%</td>
<td>Line 545 125</td>
</tr>
<tr>
<td>10m mva</td>
<td>Line 600 137</td>
<td>mva</td>
<td>Line 560 132</td>
</tr>
<tr>
<td>5m 110</td>
<td>Line 650 149</td>
<td>110</td>
<td>Line 580 133</td>
</tr>
<tr>
<td>3m 99</td>
<td>Line 680 173</td>
<td>92</td>
<td>Line 695 159</td>
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<tr>
<td>Short Term Overloads</td>
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<tr>
<td>6hr 75%</td>
<td>Line 580 132</td>
<td>75%</td>
<td>Line 540 123</td>
</tr>
<tr>
<td>20m 60%</td>
<td>Line 605 138</td>
<td>60%</td>
<td>Line 560 128</td>
</tr>
<tr>
<td>10m mva</td>
<td>Line 675 155</td>
<td>mva</td>
<td>Line 620 142</td>
</tr>
<tr>
<td>5m 79</td>
<td>Line 820 187</td>
<td>73</td>
<td>Line 750 172</td>
</tr>
<tr>
<td>3m 39</td>
<td>Line 985 226</td>
<td>36</td>
<td>Line 900 206</td>
</tr>
<tr>
<td>Limiting Item and permitted overload values for different times and pre-fault loads</td>
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<td></td>
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</tr>
<tr>
<td>6hr 30%</td>
<td>Line 580 132</td>
<td>30%</td>
<td>Line 540 123</td>
</tr>
<tr>
<td>20m 60%</td>
<td>Line 615 141</td>
<td>60%</td>
<td>Line 570 130</td>
</tr>
<tr>
<td>10m mva</td>
<td>Line 710 163</td>
<td>mva</td>
<td>Line 655 150</td>
</tr>
<tr>
<td>5m 39</td>
<td>Line 895 205</td>
<td>36</td>
<td>Line 820 187</td>
</tr>
<tr>
<td>3m 11</td>
<td>Line 1110 255</td>
<td>10</td>
<td>Line 1010 230</td>
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<tr>
<td>Notes or Restrictions</td>
<td>Detailed</td>
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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 or ECC.5.2.1)

SUBSTATION OPERATIONAL GUIDE

Substation: __________________________

Location Details:

<table>
<thead>
<tr>
<th>Postal Address</th>
<th>Telephone Nos.</th>
<th>Map Ref.</th>
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</thead>
<tbody>
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</table>

Transmission Interface

Generator Interface

1. Substation Type:

2. Voltage Control: (short description of voltage control system. To include mention of modes i.e. Voltage, manual etc. Plus control step increments i.e. 0.5% or 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 (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.
  - Demand with all OTSDUW DC Converters operating at maximum Interface Point flow from the Interface Point to each Offshore Grid Entry Point.
  - The maximum Demand that could occur.
  - Demand at specified time of annual peak half hour of The Company Demand at Annual ACS Conditions.
  - Demand at specified time of annual minimum half-hour of The Company Demand.

OTSDUW DC CONVERTER DATA

Number of poles, i.e. number of OTSDUW DC Converters

Pole arrangement (e.g. monopole or bipole)

Return path arrangement

Details of each viable operating configuration

<table>
<thead>
<tr>
<th>Data Description</th>
<th>Units</th>
<th>Data to RTL</th>
<th>Data Category</th>
<th>DC Converter Station Data</th>
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<td>(PC.A.4 and PC.A.5.2.5)</td>
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<td>OTSDUW DC CONVERTER DATA</td>
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<tr>
<td>Number of poles, i.e. number of OTSDUW DC Converters</td>
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<td>■</td>
<td>SPD+</td>
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<tr>
<td>Pole arrangement (e.g. monopole or bipole)</td>
<td>Diagram</td>
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<tr>
<td>Return path arrangement</td>
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<tr>
<td>Details of each viable operating configuration</td>
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<tr>
<td>Configuration 1</td>
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<td>■</td>
<td>SPD+</td>
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<tr>
<td>Configuration 2</td>
<td>Diagram</td>
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<td>Configuration 4</td>
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<td>Configuration 6</td>
<td>Diagram</td>
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<tr>
<td><strong>OTSDUW DC CONVERTER DATA</strong> <em>(PC.A.3.3.1(d))</em></td>
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<td>CUSC Contract</td>
<td>CUSC App. Form</td>
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<tr>
<td>OTSDUW DC Converter Type <em>(e.g. current or Voltage source)</em></td>
<td>Text</td>
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<td>■ SPD</td>
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<tr>
<td>If the busbars at the <strong>Interface Point</strong> or <strong>Connection Point</strong> are normally run in separate sections identify the section to which the OTSDUW DC Converter configuration is connected</td>
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<td>MW</td>
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<td>■ SPD</td>
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<td>Interface Point Capacity</td>
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<td>■ SPD</td>
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<tr>
<td></td>
<td>MVAR</td>
<td>□</td>
<td>■ SPD</td>
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<td>Rated MVA</td>
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<td>Nominal secondary <em>(converter-side)</em> voltage(s)</td>
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<td>DPD II</td>
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<tr>
<td>Positive sequence reactance</td>
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<td>Minimum tap</td>
<td>MVA</td>
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<td>Zero phase sequence reactance</td>
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<td>Tap change range</td>
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<tr>
<td><strong>OTSDUW DC CONVERTER NETWORK DATA</strong> (PC.A.5.4.3.1 (c))</td>
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<td>CUSC Contract</td>
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<td>Rated DC voltage per pole</td>
<td>kV</td>
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<tr>
<td>Rated DC current per pole</td>
<td>A</td>
<td>□</td>
<td>DPD II</td>
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<tr>
<td>Details of the <strong>OTSDUW DC Network</strong> 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 <strong>OTSDUW DC Network</strong> should be shown.</td>
<td>Diagram</td>
<td>□</td>
<td>DPD II</td>
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<tr>
<td>Data Description</td>
<td>Units</td>
<td>DATA to RTL</td>
<td>Data Category</td>
<td>Operating configuration</td>
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<td>CUSC Contract</td>
<td>CUSC App Form</td>
<td>1 2 3 4 5 6</td>
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<td>OTSDUW DC CONVERTER CONTROL SYSTEMS (PC.A.5.4.3.2)</td>
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<tr>
<td>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</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>Details of rectifier mode control system, in block diagram form together with parameters showing transfer functions of individual elements.</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>Details of inverter mode control system, in block diagram form showing transfer functions of individual elements including parameters (as applicable).</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>Details of <strong>OTSDUW DC Converter</strong> transformer tap changer control system in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>Details of AC filter control systems in block diagram form showing transfer functions of individual elements including parameters</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>Details of any frequency and/or load control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>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.</td>
<td>Diagram □</td>
<td>DPD II</td>
<td></td>
<td></td>
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<tr>
<td>Transfer block diagram representation of the reactive power control at converter ends for a voltage source converter.</td>
<td>Diagram □</td>
<td>DPD II</td>
<td></td>
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</tr>
<tr>
<td>For <strong>Generators</strong> in respect of <strong>OTSDUW</strong> who are also <strong>EU Code Users</strong> details of <strong>OTSDUW DC Converter</strong> unit models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>Diagram □</td>
<td>DPD II</td>
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<tr>
<td>For <strong>Generators</strong> in respect of <strong>OTSDUW</strong> who are also <strong>EU Code Users</strong> details of AC component models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
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<tr>
<td>For <strong>Generators</strong> in respect of <strong>OTSDUW</strong> who are also <strong>EU Code Users</strong> details of DC Grid models and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td>Diagram □</td>
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<tr>
<td>For <strong>Generators</strong> in respect of <strong>OTSDUW</strong> who are also <strong>EU Code Users</strong> details of Voltage and power controller and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
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<td>DPD II</td>
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<tr>
<td>For <strong>Generators</strong> in respect of <strong>OTSDUW</strong> who are also <strong>EU Code Users</strong> details of Special control features if applicable (e.g. power oscillation</td>
<td>Diagram □</td>
<td>DPD II</td>
<td></td>
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<tr>
<td>Data Description</td>
<td>Units</td>
<td>DATA to RTL</td>
<td>Data Category</td>
<td>Operating configuration</td>
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<td>--------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
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<tr>
<td>damping (POD) function, subsynchronous torsional interaction (SSTI) control and/or control systems in block diagram form showing transfer functions of individual elements including parameters. For Generators in respect of OTSDUW who are also EU Code Users details of Multi terminal control, if applicable and/or control systems in block diagram form showing transfer functions of individual elements including parameters. For Generators in respect of OTSDUW who are also EU Code Users details of OTSDUW DC Converter protection models as agreed between The Company and the Generator (in respect of OTSDW) and/or control systems in block diagram form showing transfer functions of individual elements including parameters.</td>
<td></td>
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<td>DPD II</td>
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Diagram □ DPD II
Diagram □ DPD II
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<td><strong>LOADING PARAMETERS (PC.A.5.4.3.3)</strong></td>
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<td>MW Export from the <strong>Offshore Grid Entry Point</strong> to the <strong>Transmission Interface Point</strong></td>
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<tr>
<td>Nominal loading rate</td>
<td>MW/s</td>
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<td>DPD I</td>
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<tr>
<td>Maximum (emergency) loading rate</td>
<td>MW/s</td>
<td>□</td>
<td>DPD I</td>
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<tr>
<td>Maximum recovery time, to 90% of pre-fault loading, following an AC system fault or severe voltage depression.</td>
<td>s</td>
<td>□</td>
<td>DPD II</td>
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<tr>
<td>Maximum recovery time, to 90% of pre-fault loading, following a transient DC Network fault.</td>
<td>s</td>
<td>□</td>
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The structure of the **User Data File Structure** is given below.

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<th>Description of contents</th>
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<tr>
<td>A2</td>
<td>Commissioning</td>
<td>Commissioning &amp; Test Programmes</td>
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<tr>
<td>A3</td>
<td>Statements</td>
<td>Statements of Readiness</td>
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<td>A9</td>
<td>AS Monitoring</td>
<td>Ancillary Services Monitoring</td>
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<td>A10</td>
<td>Self-Certification</td>
<td>User Self Certification of Compliance</td>
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<tr>
<td>A11</td>
<td>Compliance statements</td>
<td>Compliance Statement</td>
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<td>Local Switching Procedures</td>
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<td>Operational and Gas Zone Diagrams</td>
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<td>1.7</td>
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<td>Site Common Drawings</td>
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<td>Tel Numbers</td>
<td>Telephone Numbers for Joint System Incidents</td>
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<td>Contact Details</td>
<td>Contact Details (fax, tel, email)</td>
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<td>Restoration Plan</td>
<td>Local Joint Restoration Plan (incl. black start if applicable)</td>
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<td>Special Automatic Facilities</td>
<td>Special Automatic Facilities e.g. intertrip</td>
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### Part 3: Generator Technical Data

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<td>DRC Schedule 4</td>
<td>DRC Schedule 4 – Frequency Droop &amp; Response</td>
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<td>DRC Schedule 14</td>
<td>DRC Schedule 14 – Fault Infeed Data – Generators</td>
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<td>Special Generator Protection e.g. Pole slipping; islanding</td>
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<td>Compliance Simulation Studies</td>
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### Part 4: General DRC Schedules

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<td>DRC Schedule 8</td>
<td>DRC Schedule 8 – BM Unit Data (if applicable)</td>
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<td>DRC Schedule 10</td>
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### Part 5: OTSDUW Data and Information

(if applicable and prior to OTSUA Transfer Time)

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<td></td>
<td></td>
<td>Automatic Control Systems</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Mathematical model of dynamic compensation plant</td>
</tr>
</tbody>
</table>
SCHEDULE 20 – GRID FORMING PLANT CAPABILITY DATA

The following data need only be supplied by Users (be they a GB Code User or EU Code User) or Non-CUSC Parties who wish to offer a Grid Forming Capability as provided for ECC.6.3.19.3. Where such a Grid Forming Capability is provided then the following data items and models are to be supplied in respect of each Grid Forming Plant.

<table>
<thead>
<tr>
<th>DATA DESCRIPTION</th>
<th>GRID FORMING PLANT DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Submission of Network Frequency Perturbation Plot and Nichols Chart for each GBGF-I (PC.A.5.8.1)</td>
<td>Graphs</td>
</tr>
<tr>
<td>High level equivalent architecture diagram of Grid Forming Plant (PC.A.5.8.1)</td>
<td>Diagram</td>
</tr>
<tr>
<td>GBGF-I Grid Forming Plant Block Diagram (Laplace Operator) in the general form shown in Figure PC.A.5.8.1 or as agreed with The Company.</td>
<td>Block Diagram (Laplace Operator)</td>
</tr>
<tr>
<td></td>
<td>Documentation</td>
</tr>
<tr>
<td>Each User or Non-CUSC Party shall provide a model of their Grid Forming Plant which provides a true and accurate reflection of its Grid Forming Capability.</td>
<td>Model and documentation – format to be agreed with The Company</td>
</tr>
</tbody>
</table>

In order to participate in the Grid Forming Capability market, User’s and Non-CUSC Parties are required to provide data of their GBGF-I in accordance with Figures PC.A.5.8.1(a) and PC.A.5.8.1(b) Users and Non-CUSC Parties in respect of Grid Forming Plants should indicate if the data is submitted on a unit or aggregated basis. Table 1 below defines the notation used in Figure PC.5.8.1
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>The primary reactance of the Grid Forming Unit, in pu.</td>
<td>Xin or Xts</td>
<td>pu on MVA Rating of Grid Forming Unit</td>
</tr>
<tr>
<td>The additional reactance, in pu, between the terminals of the Grid Forming Unit and the Grid Entry Point or User System Entry Point (if Embedded).</td>
<td>Xtr</td>
<td>pu on MVA Rating of Grid Forming Unit</td>
</tr>
<tr>
<td>The rated angle between the Internal Voltage Source and the input terminals of the Grid Forming Unit.</td>
<td>radians</td>
<td></td>
</tr>
<tr>
<td>The rated angle between the Internal Voltage Source and Grid Entry Point or User System Entry Point (if Embedded).</td>
<td>radians</td>
<td></td>
</tr>
<tr>
<td>The rated voltage and phase of the Internal Voltage Source of the Grid Forming Unit.</td>
<td>Voltage - pu Phase - radians</td>
<td></td>
</tr>
<tr>
<td>The rated electrical angle between current and voltage at the input to the Grid transformer.</td>
<td>radians</td>
<td></td>
</tr>
</tbody>
</table>

Table 1

In order to participate in a Grid Forming Capability market, User's and Non-CUSC Parties are also required to provide the data of their GBGF-I in accordance with the Table below to The Company. The details and arrangements for Users and Non-CUSC Parties participating in this market shall be published on The Company's Website.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Units</th>
<th>Range (where Applicable)</th>
<th>User Defined Parameter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type of Grid form Plant (eg Generating Unit, Electricity Storage Module, Dynamic Reactive Compensation Equipment)</td>
<td>N/A</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum Continuous Rating at Registered Capacity or Maximum Capacity</td>
<td>MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Primary reactance Xin or Xts(see Table 1)</td>
<td>pu on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Additional reactance Xtr (See Table 1)</td>
<td>pu on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Maximum Capacity</strong></td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td>----------------------</td>
<td>----</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Active ROCOF Response Power (MW)</strong> supplied or absorbed at 1Hz/s <strong>System Frequency</strong> change (which is the maximum frequency change for linear operation of the <strong>Grid Forming Plant</strong>)</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Phase Jump Angle Withstand</strong></td>
<td>degrees</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Phase Jump Angle limit</strong></td>
<td>degrees</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Phase Jump Power (MW) at the rated angle</strong></td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Defined Active Damping Power for a Grid Oscillation Value</strong> of 0.05 Hz peak to peak at 1 Hz</td>
<td>MW</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>The cumulative energy delivered for a 1Hz/s System Frequency</strong> fall from 52 Hz to 47 Hz This is the total <strong>Active Power</strong> transient output of the <strong>Grid Forming Plant</strong></td>
<td>MWs or MJ</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Inertia Constant (H)</strong> using equation 1 or declared in accordance with the simulation results of <strong>ECP.A.3.9.4</strong></td>
<td>MWs/MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Inertia Constant (He)</strong> using equation 2 or declared in accordance with the simulation results of <strong>ECP.A.3.9.4</strong></td>
<td>MWs/MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Continuous Overload Capability</strong></td>
<td>% on MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Short Term duration Overload capability</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Duration of Short Term Overload Capability</strong></td>
<td>s</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Peak Current Rating</strong></td>
<td>pu</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Nominal Grid Entry Point or User System Entry Point voltage</strong></td>
<td>kV</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Grid Entry Point or User System Entry Point</strong></td>
<td>- Location</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Continuous or defined time duration MVA Rating</strong></td>
<td>MVA</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Continuous or defined time duration MW Rating</strong></td>
<td>MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
For a GBGF-I the inverters maximum Internal Voltage Source (IVS) for the worst case condition – for example operation at maximum exporting Reactive Power at the maximum AC System voltage

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Three Phase Short Circuit Infeed at Grid Entry Point or User System Entry Point</td>
<td>kA</td>
</tr>
<tr>
<td>Maximum Single Phase Short Circuit Infeed at Grid Entry Point or User System Entry Point</td>
<td>kA</td>
</tr>
<tr>
<td>Will the Grid Forming Plant contribute to any other form of commercial service – for example Dynamic Containment, Firm Frequency Response,</td>
<td>Details to be provided</td>
</tr>
<tr>
<td>Equivalent Damping Factor.</td>
<td>$\zeta$</td>
</tr>
</tbody>
</table>

Table 2

$H = \frac{\text{Installed MWs}}{\text{Rated installed MVA}}$  
(equation 1)

$H_e = \frac{\text{Active ROCOF Response Power at 1 Hz / s x System Frequency}}{\text{Installed MVA x 2}}$  
(equation 2)
# GENERAL CONDITIONS

**(GC)**

## CONTENTS

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

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<th>Page Number</th>
</tr>
</thead>
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<tr>
<td>GC.2 SCOPE</td>
<td>2</td>
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<tr>
<td>GC.3 UNFORESEEN CIRCUMSTANCES</td>
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<tr>
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<td>2</td>
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</tr>
<tr>
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</tr>
</tbody>
</table>
INTRODUCTION

The General Conditions contain provisions which are of general application to all provisions of the Grid Code. Their objective is to ensure, to the extent possible, that the various sections of the Grid Code work together and work in practice for the benefit of all Users.

SCOPE

The General Conditions apply to all Users (including, for the avoidance of doubt, The Company).

UNFORESEEN CIRCUMSTANCES

If circumstances arise which the provisions of the Grid Code have not foreseen, The Company shall, to the extent reasonably practicable in the circumstances, consult promptly and in good faith all affected Users in an effort to reach agreement as to what should be done. If agreement between The Company and those Users as to what should be done cannot be reached in the time available, The Company shall determine what is to be done. Wherever The Company makes a determination, it shall do so having regard, wherever possible, to the views expressed by Users and, in any event, to what is reasonable in all the circumstances. Each User shall comply with all instructions given to it by The Company following such a determination provided that the instructions are consistent with the then current technical parameters of the particular User’s System registered under the Grid Code. The Company shall promptly refer all such unforeseen circumstances and any such determination to the Panel for consideration in accordance with GC.4.2(e).

COMMUNICATION BETWEEN THE COMPANY AND USERS

Unless otherwise specified in the Grid Code, all instructions given by The Company and communications (other than relating to the submission of data and notices) between The Company and Users (other than Generators, DC Converter Station owners or Suppliers) shall take place between the The Company Control Engineer based at the Transmission Control Centre notified by The Company to each User prior to connection, and the relevant User Responsible Engineer/Operator, who, in the case of a Network Operator, will be based at the Control Centre notified by the Network Operator to The Company prior to connection.

Unless otherwise specified in the Grid Code, all instructions given by The Company and communications (other than relating to the submission of data and notices) between The Company and Generators and/or DC Converter Station owners and/or Suppliers, shall take place between the The Company Control Engineer based at the Transmission Control Centre notified by The Company to each Generator or DC Converter Station owner prior to connection, or to each Supplier prior to submission of BM Unit Data, and either the relevant Generator’s or DC Converter Station owner’s or Supplier’s Trading Point (if it has established one) notified to The Company or the Control Point of the Supplier or the Generator’s Power Station or DC Converter Station, as specified in each relevant section of the Grid Code. In the absence of notification to the contrary, the Control Point of a Generator’s Power Station will be deemed to be the Power Station at which the Generating Units or Power Park Modules are situated.

Unless otherwise specified in the Grid Code, all instructions given by The Company and communications (other than relating to the submission of data and notices) between The Company and Users will be given by means of the Control Telephony referred to in CC.6.5.2.
If the Transmission Control Centre notified by The Company to each User prior to connection, or the User Control Centre, notified in the case of a Network Operator to The Company prior to connection, is moved to another location, whether due to an emergency or for any other reason, The Company shall notify the relevant User or the User shall notify The Company, as the case may be, of the new location and any changes to the Control Telephony or System Telephony necessitated by such move, as soon as practicable following the move.

If any Trading Point notified to The Company by a Generator or DC Converter Station owner prior to connection, or by a Supplier prior to submission of BM Unit Data, is moved to another location or is shut down, the Generator, DC Converter Station owner or Supplier shall immediately notify The Company.

The recording (by whatever means) of instructions or communications given by means of Control Telephony or System Telephony will be accepted by The Company and Users as evidence of those instructions or communications.

Data and notices to be submitted either to The Company or to Users under the Grid Code (other than data which is the subject of a specific requirement of the Grid Code as to the manner of its delivery) shall be delivered in writing either by hand or sent by first-class pre-paid post, or by facsimile transfer or by electronic mail to a specified address or addresses previously supplied by The Company or the User (as the case may be) for the purposes of submitting that data or those notices.

References in the Grid Code to “in writing” or “written” include typewriting, printing, lithography, and other modes of reproducing words in a legible and non-transitory form and in relation to submission of data and notices includes electronic communications.

Data delivered pursuant to paragraph GC.6.1.1, in the case of data being submitted to The Company, shall be addressed to the Transmission Control Centre at the address notified by The Company to each User prior to connection, or to such other Department within The Company or address, as The Company may notify each User from time to time, and in the case of notices to be submitted to Users, shall be addressed to the chief executive of the addressee (or such other person as may be notified by the User in writing to The Company from time to time) at its address(es) notified by each User to The Company in writing from time to time for the submission of data and service of notices under the Grid Code (or failing which to the registered or principal office of the addressee).

All data items, where applicable, will be referenced to nominal voltage and Frequency unless otherwise stated.

References in the Grid Code to Plant and/or Apparatus of a User include Plant and/or Apparatus used by a User under any agreement with a third party.

Where a User’s System (or part thereof) is, by agreement, under the control of The Company, then for the purposes of communication and co-ordination in operational timescales The Company can (for those purposes only) treat that User’s System (or part thereof) as part of the National Electricity Transmission System, but, as between The Company and Users, it shall remain to be treated as the User’s System (or part thereof).

EMERGENCY SITUATIONS
Users should note that the provisions of the Grid Code may be suspended, in whole or in part, during a Security Period, as more particularly provided in the Fuel Security Code, or pursuant to any directions given and/or orders made by the Secretary of State under section 96 of the Act or under the Energy Act 1976.

GC.10 MATTERS TO BE AGREED

Save where expressly stated in the Grid Code to the contrary where any matter is left to The Company and Users to agree and there is a failure so to agree the matter shall not without the consent of both The Company and Users be referred to arbitration pursuant to the rules of the Electricity Supply Industry Arbitration Association.

GC.11 GOVERNANCE OF ELECTRICAL STANDARDS

GC.11.1 In relation to the Electrical Standards the following provisions shall apply.

GC.11.2 (a) If a User, or in respect of the Electrical Standards in (b) to the annex, The Company, or in respect of the Electrical Standards in (c) or (d) to the annex, the Relevant Scottish Transmission Licensee, wishes to:

(i) raise a change to an Electrical Standard;
(ii) add a new standard to the list of Electrical Standards;
(iii) delete a standard from being an Electrical Standard,

it shall activate the Electrical Standards procedure.

(b) The Electrical Standards procedure is the notification to the secretary to the Panel of the wish to so change, add or delete an Electrical Standard. That notification must contain details of the proposal, including an explanation of why the proposal is being made.

GC.11.3 Ordinary Electrical Standards Procedure

(a) Unless it is identified as an urgent Electrical Standards proposal (in which case GC.11.4 applies) or unless the notifier requests that it be tabled at the next Panel meeting, as soon as reasonably practicable following receipt of the notification, the Panel secretary shall forward the proposal, with a covering paper, to Panel Members.

(b) If no objections are raised within 20 Business Days of the date of the proposal, then it shall be deemed approved pursuant to the Electrical Standards procedure, and The Company shall make the change to the relevant Electrical Standard or the list of Electrical Standards contained in the Annex to this GC.11.

(c) If there is an objection (or if the notifier had requested that it be tabled at the next Panel meeting rather than being dealt with in writing), then the proposal will be included in the agenda for the next following Panel meeting.

(d) If there is broad consensus at the Panel meeting in favour of the proposal, The Company will make the change to the Electrical Standard or the list of Electrical Standards contained in the Annex to this GC.11.

(e) If there is no such broad consensus, including where the Panel believes that further consultation is needed, The Company will establish a Panel working group if this was thought appropriate and in any event The Company shall undertake a consultation of Authorised Electricity Operators liable to be materially affected by the proposal.

(f) Following such consultation, The Company will report back to Panel Members, either in writing or at a Panel meeting. If there was broad consensus in the consultation, then The Company will make the change to the Electrical Standard or the list of Electrical Standards contained in the Annex to this GC.11.
(g) Where following such consultation there is no broad consensus, the matter will be referred to the **Authority** who will decide whether the proposal should be implemented and will notify **The Company** of its decision. If the decision is to so implement the change, **The Company** will make the change to the **Electrical Standard** or the list of **Electrical Standards** contained in the Annex to this GC.11.

(h) In all cases where a change is made to the list of **Electrical Standards**, **The Company** will publish and circulate a replacement page for the Annex to this GC covering that list and reflecting the change.

**GC.11.4 Urgent Electrical Standards Procedure**

(a) If the notification is marked as an urgent **Electrical Standards** proposal, the **Panel** secretary will contact **Panel Members** in writing to see whether a majority who are contactable agree that it is urgent and in that notification the secretary shall propose a timetable and procedure which shall be followed.

(b) If such members do so agree, then the secretary will initiate the procedure accordingly, having first obtained the approval of the **Authority**.

(c) If such members do not so agree, or if the **Authority** declines to approve the proposal being treated as an urgent one, the proposal will follow the ordinary **Electrical Standards** procedure as set out in GC.11.3 above.

(d) If a proposal is implemented using the urgent **Electrical Standards** procedure, **The Company** will contact all **Panel Members** after it is so implemented to check whether they wish to discuss further the implemented proposal to see whether an additional proposal should be considered to alter the implementation, such proposal following the ordinary **Electrical Standards** procedure.

**GC.12 CONFIDENTIALITY**

**GC.12.1** **Users** should note that although the Grid Code contains in certain sections specific provisions which relate to confidentiality, the confidentiality provisions set out in the CUSC apply generally to information and other data supplied as a requirement of or otherwise under the Grid Code. To the extent required to facilitate the requirements of the EMR Documents, **Users** that are party to the Grid Code but are not party to the CUSC Framework Agreement agree that the confidentiality provisions of the CUSC are deemed to be imported into the Grid Code.

**GC.12.2** **The Company** has obligations under the STC to inform **Relevant Transmission Licensees** of certain data. **The Company** may pass on **User** data to a **Relevant Transmission Licensee** where:

(a) **The Company** is required to do so under a provision of Schedule 3 of the STC; and/or

(b) permitted in accordance with PC.3.4, PC.3.5 and OC2.3.2.

**GC.12.3** **The Company** has obligations under the EMR Documents to inform **EMR Administrative Parties** of certain data. **The Company** may pass on **User** data to an EMR **Administrative Party** where **The Company** is required to do so under an EMR Document.

**GC.12.4** **The Company** may use **User** data for the purpose of carrying out its **EMR Functions**.

**GC.13 RELEVANT TRANSMISSION LICENSEES**
GC.13.1 It is recognised that the Relevant Transmission Licensees are not parties to the Grid Code. Accordingly, notwithstanding that Operating Code No. 8 Appendix 1 ("OC8A") and Appendix 2 ("OC8B"), OC7.6, OC9.4 and OC9.5 refer to obligations which will in practice be performed by the Relevant Transmission Licensees in accordance with relevant obligations under the STC, for the avoidance of doubt all contractual rights and obligations arising under OC8A, OC8B, OC7.6, OC9.4 and OC9.5 shall exist between The Company and the relevant User and in relation to any enforcement of those rights and obligations OC8A, OC8B, OC7.6, OC9.4 and OC9.5 shall be so read and construed. The Relevant Transmission Licensees shall enjoy no enforceable rights under OC8A, OC8B, OC7.6, OC9.4 and OC9.5 nor shall they be liable (other than pursuant to the STC) for failing to discharge any obligations under OC8A, OC8B, OC7.6, OC9.4 and OC9.5.

GC.13.2 For the avoidance of doubt nothing in this Grid Code confers on any Relevant Transmission Licensee any rights, powers or benefits for the purpose of the Contracts (Rights of Third Parties) Act 1999.

GC.14 BETTA TRANSITION ISSUES

GC.14.1 The provisions of Part A of the Appendix to the General Conditions apply in relation to issues arising out of the transition associated with the designation of GC Modification Proposals by the Secretary of State in accordance with the provisions of the Energy Act 2004 for the purposes of Condition C14 of The Company’s Transmission Licence.

GC.15 EMBEDDED EXEMPTABLE LARGE AND MEDIUM POWER STATIONS

GC.15.1 This GC.15.1 shall have an effect until and including 31st March 2007.

(i) CC.6.3.2, CC.6.3.7, CC.8.1 and BC3.5.1; and

(ii) Planning Code obligations and other Connection Conditions; shall apply to a User who owns or operates an Embedded Exemptable Large Power Station, or a Network Operator in respect of an Embedded Exemptable Medium Power Station, except where and to the extent that, in respect of that Embedded Exemptable Large Power Station or Embedded Exemptable Medium Power Station, The Company agrees or where the relevant User and The Company fail to agree, where and to the extent that the Authority consents.

GC.16 NOT USED
ANNEX TO THE GENERAL CONDITIONS

The Electrical Standards are as follows:

(a) Electrical Standards applicable for NGET’s Transmission System

<table>
<thead>
<tr>
<th>The Relevant Electrical Standards Document (RES)</th>
<th>Reference</th>
<th>Issue</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Parts 1 to 3</td>
<td></td>
<td>3.0</td>
<td>March 2018</td>
</tr>
<tr>
<td>Part 4 – Specific Requirements</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1 Back-Up Protection Grading across NGET’s and other Network Operator Interfaces</td>
<td>PS(T)044(RES)</td>
<td>1.0</td>
<td>September 2014</td>
</tr>
<tr>
<td>2 Ratings and General Requirements for Plant, Equipment, Apparatus and Services for the National Grid System and Connections Points to it.</td>
<td>TS 1 (RES)</td>
<td>1.0</td>
<td>February 2018</td>
</tr>
<tr>
<td>3 Substations</td>
<td>TS 2.01 (RES)</td>
<td>1.0</td>
<td>February 2018</td>
</tr>
<tr>
<td>4 Switchgear</td>
<td>TS 2.02 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>5 Substation Auxiliary Supplies</td>
<td>TS 2.12 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>6 Ancillary Light Current Equipment</td>
<td>TS 2.19 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>7 Substation Interlocking Schemes</td>
<td>TS 3.01.01 (RES)</td>
<td>1.0</td>
<td>February 2018</td>
</tr>
<tr>
<td>8 Earthing Requirements</td>
<td>TS 3.01.02 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>9 Circuit Breakers</td>
<td>TS 3.02.01 (RES)</td>
<td>2.0</td>
<td>February 2018</td>
</tr>
<tr>
<td>10 Disconnectors and Earthing Switches</td>
<td>TS 3.02.02 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>11 Current Transformers for Protection and General Use on the 132kV, 275kV and 400kV Systems</td>
<td>TS 3.02.04 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>12 Voltage Transformers</td>
<td>TS 3.02.05 (RES)</td>
<td>1.0</td>
<td>September 2016</td>
</tr>
<tr>
<td>13 Bushings</td>
<td>TS 3.02.07 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
</tr>
<tr>
<td>14 Solid Core Post Insulators for Substations</td>
<td>TS 3.02.09 (RES)</td>
<td>1.0</td>
<td>October 2014</td>
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<tr>
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6. NGTS 3.2.3: Metal-Oxide surge arresters for use on 132, 275 and 400kV systems. Issue 2 May 1994.
7. NGTS 3.2.4: Current Transformers for protection and General use on the 132, 275 and 400kV systems. Issue 1 September 1992.
8. NGTS 3.2.5: Voltage Transformers for use on the 132, 275 and 400 kV systems. Issue 2 March 1994.
11. NGTS 3.2.9: Post Insulators for Substations. Issue 1 May 1996.
APPENDIX TO THE GENERAL CONDITIONS

PART A

GC.A.1 Introduction

GC.A.1.1 This Appendix Part A to the General Conditions deals with issues arising out of the transition associated with the designation of amendments to the Grid Code by the Secretary of State in accordance with the provisions of the Energy Act 2004 for the purposes of Condition C14 of The Company’s Transmission Licence at that time. For the purposes of this Appendix to the General Conditions, the version of the Grid Code as amended by the changes designated by the Secretary of State and as further amended from time to time shall be referred to as the “GB Grid Code”. The process and amendments referred to in this Appendix Part A took place before the separation of The Company from NGET and the introduction into the Grid Code of Offshore Transmission Licencees and this Part A shall be construed accordingly.

GC.A.1.2 The provisions of this Appendix Part A to the General Conditions shall only apply to Users (as defined in GC.A.1.4) and The Company after Go-Live for so long as is necessary for the transition requirements referred to in GC.A.1.1 and cut-over requirements (as further detailed in GC.A.3.1) to be undertaken.

GC.A.1.3 In this Appendix Part A to the General Conditions:

(a) Existing E&W Users and E&W Applicants are referred to as “E&W Users”;

(b) Users who as at 1 January 2005 have entered into an agreement or have accepted an offer for connection to and/or use of the Transmission System of NGET are referred to as “Existing E&W Users”;

(c) Users (or prospective Users) other than Existing E&W Users who apply during the Transition Period for connection to and/or use of the Transmission System of NGET are referred to as “E&W Applicants”;

(d) Existing Scottish Users and Scottish Applicants are referred to as “Scottish Users”;

(e) Users who as at 1 January 2005 have entered into an agreement or have accepted an offer for connection to and/or use of the Transmission System of either SPT or SHETL are referred to as “Existing Scottish Users”;

(f) Users (or prospective Users) other than Existing Scottish Users who apply during the Transition Period for connection to and/or use of the Transmission System of either SPT or SHETL are referred to as “Scottish Applicants”;

(g) the term “Transition Period” means the period from Go-Active to Go-Live (unless it is provided to be different in relation to a particular provision), and is the period with which this Appendix Part A to the General Conditions deals;

(h) the term “Interim GB SYS” means the document of that name referred to in Condition C11 of The Company’s Transmission Licence;

(i) the term “Go-Active” means the date on which the amendments designated by the Secretary of State to the Grid Code in accordance with the Energy Act 2004 come into effect; and

(j) the term “Go-Live” means the date which the Secretary of State indicates in a direction shall be the BETTA go-live date.

GC.A.1.4 The provisions of GC.2.1 shall not apply in respect of this Appendix to the General Conditions, and in this Appendix Part A to the General Conditions the term “Users” means:

(a) Generators;

(b) Network Operators;

(c) Non-Embedded Customers;

(d) Suppliers;
(e) **BM Participants**;

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

(g) **DC Converter Station** owners

to the extent that the provisions of this Appendix Part A to the **General Conditions** affect the rights and obligations of such **Users** under the other provisions of the GB Grid Code.

**GC.A.1.5** The GB Grid Code has been introduced with effect from **Go-Active** pursuant to the relevant licence changes introduced into **The Company’s Transmission Licence**. **The Company** is required to implement and comply, and **Users** to comply, with the GB Grid Code subject as provided in this Appendix Part A to the **General Conditions**, which provides for the extent to which the GB Grid Code is to apply to **The Company** and **Users** during the **Transition Period**.

**GC.A.1.6** This Appendix Part A to the **General Conditions** comprises:

(a) this Introduction;

(b) GB Grid Code transition issues; and

(c) Cut-over issues.

**GC.A.1.7** Without prejudice to GC.A.1.8, the failure of any **User** or **The Company** to comply with this Appendix Part A to the **General Conditions** shall not invalidate or render ineffective any part of this Appendix Part A to the **General Conditions** or actions undertaken pursuant to this Appendix to the **General Conditions**.

**GC.A.1.8** A **User** or **The Company** shall not be in breach of any part of this Appendix Part A to the **General Conditions** to the extent that compliance with that part is beyond its power by reason of the fact that any other **User** or **The Company** is in default of its obligations under this Appendix Part A to the **General Conditions**.

(a) take such step or measure as quickly as reasonably practicable; and

(b) do such associated or ancillary things as may be necessary to complete such step or measure as quickly as reasonably practicable.

**GC.A.1.9** Without prejudice to any specific provision under this Appendix Part A to the **General Conditions** as to the time within which or the manner in which a **User** or **The Company** should perform its obligations under this Appendix to the **General Conditions**, where a **User** or **The Company** is required to take any step or measure under this Appendix Part A to the **General Conditions**, such requirement shall be construed as including any obligation to:

(a) use reasonable endeavours to identify any amendments it believes are needed to the GB Grid Code in respect of the matters referred to for the purposes of Condition C14 of **The Company’s Transmission Licence** and in respect of the matters identified in GC.A.1.11, and, having notified the **Authority** of its consultation plans in relation to such amendments, **The Company** shall consult in accordance with the instructions of the **Authority** concerning such proposed amendments.

**GC.A.1.10** The **Company** shall use reasonable endeavours to identify any amendments it believes are needed to the GB Grid Code in respect of the matters referred to for the purposes of Condition C14 of **The Company’s Transmission Licence** and in respect of the matters identified in GC.A.1.11, and, having notified the **Authority** of its consultation plans in relation to such amendments, **The Company** shall consult in accordance with the instructions of the **Authority** concerning such proposed amendments.

**GC.A.1.11** The following matters potentially require amendments to the GB Grid Code:

(a) **The specific detail of the obligations needed to manage implementation in the period up to and following (for a temporary period) Go-Live to achieve the change to operation under the GB Grid Code (to be included in GC.A.3)**.

(b) **Information (including data) and other requirements under the GB Grid Code applicable to Scottish Users during the Transition Period** (to be included in GC.A.2).

(c) **The conclusions of Ofgem/DTI in relation to small and/or embedded generator issues under BETTA and allocation of access rights on a GB basis**.

(d) **Any arrangements required to make provision for operational liaison, including Black Start and islanding arrangements in Scotland**.

(e) **Any arrangements required to make provision for cascade hydro BM Units**.
(f) Any consequential changes to the safety co-ordination arrangements resulting from STC and STC procedure development.

(g) Any arrangements required to reflect the Electrical Standards for the Transmission Systems of SPT and SHETL.

(h) The conclusions of Ofgem/DTI in relation to planning and operating standards.

GC.A.1.12 The Company shall notify the Authority of any amendments that The Company identifies as needed pursuant to GC.A.1.10 and shall make such amendments as the Authority approves.

GC.A.2 GB Grid Code Transition

General Provisions

GC.A.2.1 The provisions of the GB Grid Code shall be varied or suspended (and the requirements of the GB Grid Code shall be deemed to be satisfied) by or in accordance with, and for the period and to the extent set out in this GC.A.2, and in accordance with the other applicable provisions in this Appendix Part A to the General Conditions.

GC.A.2.2 E&W Users:

In furtherance of the licence provisions referred to in GC.A.1.5, E&W Users shall comply with the GB Grid Code during the Transition Period, but shall comply with and be subject to it subject to this Appendix to the General Conditions, including on the basis that:

(a) during the Transition Period the Scottish Users are only complying with the GB Grid Code in accordance with this Appendix Part A to the General Conditions; and

(b) during the Transition Period the National Electricity Transmission System shall be limited to the Transmission System of NGET, and all rights and obligations of E&W Users in respect of the National Electricity Transmission System under the GB Grid Code shall only apply in respect of the Transmission System of NGET, and all the provisions of the GB Grid Code shall be construed accordingly.

GC.A.2.3 Scottish Users:

In furtherance of the licence provisions referred to in GC.A.1.5, Scottish Users shall comply with the GB Grid Code and the GB Grid Code shall apply to or in relation to them during the Transition Period only as provided in this Appendix Part A to the General Conditions.

GC.A.2.4 THE COMPANY:

In furtherance of the licence provisions referred to in GC.A.1.5, THE COMPANY shall implement and comply with the GB Grid Code during the Transition Period, but shall implement and comply with and be subject to it subject to, and taking into account, all the provisions of this Appendix Part A to the General Conditions, including on the basis that:

(a) during the Transition Period THE COMPANY’s rights and obligations in relation to E&W Users in respect of the National Electricity Transmission System under the GB Grid Code shall only apply in respect of the Transmission System of NGET, and all the provisions of the GB Grid Code shall be construed accordingly; and

(b) during the Transition Period THE COMPANY’s rights and obligations in relation to Scottish Users in respect of the National Electricity Transmission System under the GB Grid Code shall only be as provided in this Appendix Part A to the General Conditions.

Specific Provisions

GC.A.2.5 Definitions:

The provisions of the GB Grid Code Glossary and Definitions shall apply to and for the purposes of this Appendix Part A to the General Conditions except where provided to the contrary in this Appendix Part A to the General Conditions.

GC.A.2.6 Identification of Documents:
In the period beginning at Go-Active, Scottish Users will work with The Company to identify and agree with The Company any documents needed to be in place in accordance with the GB Grid Code, to apply from Go-Live or as earlier provided for under this Appendix Part A to the General Conditions, including (without limitation) Site Responsibility Schedules, Gas Zone Diagrams and OC9 Desynchronised Island Procedures.

GC.A.2.7 Data:
Each Scottish User must provide, or enable a SPT or SHETL to provide, The Company, as soon as reasonably practicable upon request, with all data which The Company needs in order to implement, with effect from Go-Live, the GB Grid Code in relation to Scotland. This data will include, without limitation, the data that a new User is required to submit to The Company under CC.5.2. The Company is also entitled to receive data on Scottish Users over SPT or SHETL’s SCADA links to the extent that The Company needs it for use in testing and in order to implement, with effect from Go-Live, the GB Grid Code in relation to Scotland. After Go-Live such data shall, notwithstanding GC.A.1.2, be treated as though it had been provided to The Company under the enduring provisions of the GB Grid Code.

GC.A.2.8 Verification of Data etc:
The Company shall be entitled to request from a Scottish User (which shall comply as soon as reasonably practicable with such a request) confirmation and verification of any information (including data) that has been received by SPT or SHETL under an existing Grid Code and passed on to The Company in respect of that Scottish User. After Go-Live such information (including data) shall, notwithstanding GC.A.1.2, be treated as though provided to The Company under the enduring provisions of the GB Grid Code.

GC.A.2.9 Grid Code Review Panel:
(a) The individuals whose names are notified to The Company by the Authority prior to Go-Active as Panel Members (and Alternate Members, if applicable) are agreed by Users (including Scottish Users) and The Company to constitute the Panel Members and Alternate Members of the Grid Code Review Panel as at the first meeting of the Grid Code Review Panel after Go-Active as if they had been appointed as Panel Members (and Alternate Members) pursuant to the relevant provisions of the Constitution and Rules of the Grid Code Review Panel incorporating amendments equivalent to the amendments to GC.4.2 and GC.4.3 designated by the Secretary of State in accordance with the provisions of the Energy Act 2004 for the purposes of Condition C14 of The Company’s Transmission Licence.

(b) The provisions of GC.4 of the GB Grid Code shall apply to, and in respect of, Scottish Users from Go-Active.

GC.A.2.10 Interim GB SYS:
Where requirements are stated in, or in relation to, the GB Grid Code with reference to the Seven Year Statement, they shall be read and construed as necessary as being with reference to the Interim GB SYS.

GC.A.2.11 General Conditions:
The provisions of GC.4, GC.12 and GC.13.2 of the GB Grid Code shall apply to and be complied with by Scottish Users in respect of this Appendix Part A to the General Conditions.

GC.A.3 Cut-over
GC.A.3.1 It is anticipated that it will be appropriate for arrangements to be put in place for final transition to BETTA in the period up to and following (for a temporary period) Go-Live, for the purposes of:

(a) managing the transition from operations under the Grid Code as in force immediately prior to Go-Active to operations under the GB Grid Code and the BSC as in force on and after Go-Active;
(b) managing the transition from operations under the existing Grid Code applicable to Scottish Users as in force immediately prior to Go-Active to operations under the GB Grid Code as in force on and after Go-Active;

(c) managing the transition of certain data from operations under the existing grid code applicable to Scottish Users before and after Go-Active; and

(d) managing GB Grid Code systems, processes and procedures so that they operate effectively at and from Go-Live.

GC.A.3.2

(a) The provisions of BC1 (excluding BC1.5.1, BC1.5.2 and BC1.5.3) shall apply to and be complied with by Scottish Users and by The Company in respect of such Scottish Users with effect from 11:00 hours on the day prior to Go-Live

(b) Notwithstanding (a) above, Scottish Users may submit data for Go-Live 3 days in advance of Go-Live on the basis set out in the Data Validation, Consistency and Defaulting Rules which shall apply to Scottish Users and The Company in respect of such Scottish Users on that basis and for such purpose.

(c) The Operational Day for the purposes of any submissions by Scottish Users prior to Go-Live under a) and b) above for the day of Go-Live shall be 00:00 hours on Go Live to 05:00 hours on the following day.

(d) The provisions of BC2 shall apply to and be complied with by Scottish Users and by The Company in respect of such Scottish Users with effect from 23:00 hours on the day prior to Go-Live.

(e) The provisions of OC7.4.8 shall apply to and be complied with by Scottish Users and by The Company in respect of such Scottish Users with effect from 11:00 hours on the day prior to Go-Live.

(f) In order to facilitate cut-over, Scottish Users acknowledge and agree that The Company will exchange data submitted by such Scottish Users under BC1 prior to Go-Live with the Scottish system operators to the extent necessary to enable the cut-over.

(g) Except in the case of Reactive Power, Scottish Users should only provide Ancillary Services from Go-Live where they have been instructed to do so by The Company. In the case of Reactive Power, at Go-Live a Scottish User's MVAr output will be deemed to be the level instructed by The Company under BC2, following this Scottish Users should operate in accordance with BC2.A.2.6 on the basis that MVAr output will be allowed to vary with system conditions.

PART B

GC.B.1 Introduction

GC.B.1.1 This Appendix Part B to the General Conditions deals with issues arising out of the transition associated with the approval and implementation of Grid Code Modification Proposal GC0112 (Modifications relating to the separation of System operations and Transmission Owner roles).

GC.B.1.2 This Appendix Part B sets out the arrangements such that:

B.1.2.1 the Post GC0112 Grid Code reflects the Transfer of the System Operator Role;

B.1.2.2 certain amendments are made to Grid Code Related Agreements/Documents to reflect the Transfer of the System Operator Role,

B.1.2.2 arrangements can be put in place prior to the SO Transfer Date to enable the transition of the operations with NGET under the Pre GC0112 Grid Code to operations with The Company under the Post GC0112 Grid Code; and

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B.1.2.3 each User co-operates in relation to the transition.

GC.B.1.3 The provisions of the Post GC0112 Grid Code shall be suspended until the SO Transfer Date except for this Appendix Part B (and any related definitions within it) which will take immediate effect on the Implementation Date for GC0112.

GC.B.1.4 In this (and solely for the purposes of this) Appendix Part B the following terms have the following meaning:

B.1.4.1 the term "Grid Code Related Agreements/Documents" shall mean each or any of those agreements or documents entered into under or envisaged by the Pre GC0112 Grid Code prior to the SO Transfer Date which continue on and after the SO Transfer Date;

B.1.4.2 the term "GC0112" shall mean Grid Code Modification Proposal 0112 (Amendments relating to the transfer of the system operator functions from NGET to NGESO);

B.1.4.3 the term "NGET" shall mean National Grid Electricity Transmission plc;

B.1.4.4 the term "NGESO" shall mean National Grid Electricity System Operator Limited;

B.1.4.5 the term "Post GC0112 Grid Code" means the version of the Grid Code as amended by GC0112;

B.1.4.6 the term "Pre GC Grid Code" means the version of the Grid Code prior to amendment by GC0112;

B.1.4.7 the term "SO Transfer Date" means the date on which NGET’s Transmission Licence is transferred in part to NGESO to reflect the Transfer of the System Operator Role; and

B.1.4.8 the term "Transfer of the System Operator Role" means the transfer, by means of the transfer in part of NGET’s Transmission Licence, of the system operator role to NGESO.

GC.B.1.5 Without prejudice to any specific provision under this Appendix Part B as to the time within which or the manner in which any party should perform its obligations under this Appendix Part B, where a party is required to take any step or measure under this Appendix Part B, such requirement shall be construed as including any obligation to:

B.1.5.1 take such step or measure as quickly as reasonably practicable; and

B.1.5.2 do such associated or ancillary things as may be necessary to complete such step or measure as quickly as reasonably practicable.

GC.B.2 GC0112: Amendments to Existing Agreements and Documents

GC.B.2.1 Each Grid Code Related Agreement/Document in place or issued by a party in accordance with the terms of the Pre GC0112 Grid Code shall be read and construed, with effect from the SO Transfer Date, as if it (and any defined terms within it and the effect of it and those defined terms) recognise and reflect the Transfer of the SO Functions and as if any references in it to NGET in the context of its system operator role were references to NGESO/The Company as appropriate.

GC.B.2.2 In the context of any Site Responsibility Schedule in existence at the SO Transfer Date and which would require, following the Transfer of the System Operator Role, the signature of either NGESO instead of NGET or both the signature of NGESO and NGET, NGESO and NGET acknowledge and the Users agree that the signature of NGET on such Site Responsibility Schedule shall be considered to be the signature of NGESO and/or NGET as appropriate.

GC.B.3 GC0112: Transition
Each party shall take such steps and do such things in relation to the Grid Code and the Grid Code Related Agreements/Documentation as are within its power and as are reasonably necessary or appropriate in order to give full and timely effect to the Transfer of the SO Role and the transition of the operations, systems, process and procedures and the rights and obligations relating to the Transfer of the SO Role under the Grid Code from NGET to NGESO.

Each party agrees that (a) all things done by NGET pursuant to the Grid Code in its system operator role prior to the SO Transfer Date shall be deemed to have been done by NGESO and (b) all things received by NGET pursuant to the Grid Code in its system operator role (including but not limited to notices) shall be deemed to have been received by NGESO and (c) all things issued by NGET (including but not limited to notices) shall be deemed to have been issued by NGESO.

In particular:

B.1.5.1 Users acknowledge and agree that NGET can exchange information and data submitted by Users under the Grid Code prior to the SO Transfer Date with NGESO to the extent necessary to enable the transition of the system operator role from NGET to NGESO;

B.1.5.2 NGET will identify and publish as soon as practicable and in any event prior to 31 January 2019 any specific requirements (such requirements being reasonable and recognising the timescale) on Users necessary to manage the transition of the operations, systems, process and procedures and the rights and obligations relating to the Transfer of the SO Role under the Grid Code from NGET to NGESO;

B.1.5.2 Users acknowledge that under the Pre GC0112 Grid Code NGET received certain data and information from Users which is no longer “live” data or information (“Legacy Data”) that if it was new data and information of that type would not be available to NGET as a Relevant Transmission Licence from the SO Transfer Date consent to the retention of such Legacy Data by NGET where embedded in NGET systems or models.
## GOVERNANCE RULES (GR)

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PART A

INTRODUCTION

GR.1

This section of the Grid Code sets out how the Grid Code is to be amended and the procedures set out in this section, to the extent that they are dealt with in the Code Administration Code of Practice, are consistent with the principles contained in the Code Administration Code of Practice. Where inconsistencies or conflicts exist between the Grid Code and the Code Administration Code of Practice, the Grid Code shall take precedence.

GR.1.2

There is a need to bring proposed amendments to the attention of Users and others, to discuss such proposals and to report on them to the Authority and in furtherance of this, the Governance Rules set out the functions of a Grid Code Review Panel and Workgroups and for consultation by the Code Administrator.

GR.1.3

For the purpose of these Governance Rules the term “User” shall mean any person who is under any obligation or granted any rights under the Grid Code.

PART B

CODE ADMINISTRATOR

GR.2

The Company shall establish and maintain a Code Administrator function, which shall carry out the roles referred to in GR.2.2 and GR.3.2. The Company shall ensure the functions are consistent with the Code Administration Code of Practice.

GR.2.2

The Code Administrator shall in conjunction with other code administrators, maintain, publish, review and (where appropriate) amend from time to time the Code Administration Code of Practice approved by the Authority provided that any amendments to the Code Administration Code of Practice proposed by the Code Administrator are approved by the Grid Code Review Panel prior to being raised by the Code Administrator, and any amendments to be made to the Code Administration Code of Practice are approved by the Authority.

THE GRID CODE REVIEW PANEL

GR.3

Establishment and Composition

GR.3.1

The Grid Code Review Panel shall be the standing body to carry out the functions referred to in GR.3.2.

GR.3.1.2

The Grid Code Review Panel shall comprise the following members:

(a) the person appointed as the chairperson of the Grid Code Review Panel (the “Panel Chairperson”) in accordance with GR.4.1, who shall (subject to GR.11.4) be a voting member unless they are an employee of The Company in which case they will be a non-voting member;

(b) the following members, appointed in accordance with GR.4.2 (a), who shall be non-voting members:

(i) a representative of the Code Administrator;
(ii) a representative of the Authority appointed in accordance with GR.4.3;
(iii) a person representing the BSC Panel appointed in accordance with GR.4.2(d); and
(iv) the chairperson of the GCDF;

(c) the following members who shall be voting Panel Members:
(i) a representative of The Company appointed in accordance with GR.4.2(c);
(ii) two representatives of the Network Operators;
(iii) a representative of Suppliers;
(iv) a representative of the Onshore Transmission Licensees;
(v) a representative of the Offshore Transmission Licensees;
(vi) four representatives of the Generators;
(vii) the Consumer Representative, appointed in accordance with GR.4.2(b);
(viii) the person appointed (if the Authority so decides) by the Authority in accordance with GR.4.4;

(d) a secretary (the “Panel Secretary”), who shall be a person appointed and provided by the Code Administrator to assist the Grid Code Review Panel and who shall be responsible for the administration of the Grid Code Review Panel and Grid Code Modification Proposals. The Panel Secretary will be a non-voting member of the Grid Code Review Panel.

GR.3.2 Functions of the Grid Code Review Panel and the Code Administrator’s Role

(a) The Grid Code Review Panel shall have the functions assigned to it in these Governance Rules.

(b) Without prejudice to GR.3.2(a) and to the further provisions of these Governance Rules, the Grid Code Review Panel shall endeavour at all times to operate:

(i) in an efficient, economical and expeditious manner, taking account of the complexity, importance and urgency of particular Grid Code Modification Proposals; and

(ii) with a view to ensuring that the Grid Code facilitates achievement of the Grid Code Objectives.

(c) The Company shall be responsible for implementing or supervising the implementation of Approved Modifications and Approved Grid Code Self Governance Proposals and Approved Grid Code Fast Track Proposals in accordance with the provisions of the Grid Code which shall reflect the production of the revised Grid Code. The Code Administrator and The Company shall be responsible for implementing and supervising the implementation of any amendments to their respective systems and processes necessary for the implementation of the Approved Modification and the Approved Grid Code Self-Governance Proposals provided there is no successful appeal and the Approved Grid Code Fast Track Proposals provided no objections are received in accordance with GR.26. However, it will not include the implementation of Users’ systems and processes. The Code Administrator will carry out its role in an efficient, economical and expeditious manner and (subject to any extension granted by the Authority where the Code Administrator has applied for one in accordance with GR.3.2(d) or (e) in accordance with the Implementation Date.

(d) Subject to notifying Users, the Code Administrator will, with the Authority’s approval, apply to the Authority for a revision or revisions to the Implementation Date where the Code Administrator becomes aware of any circumstances which is likely to mean that the Implementation Date is unachievable, which shall include as a result of a Legal Challenge, at any point following the approval of the Grid Code Modification Proposal.

(e) In the event that the Authority’s decision to approve or not to approve a Grid Code Modification Proposal is subject of Legal Challenge (and the party raising such Legal Challenge has received from the relevant authority the necessary permission to proceed) then the Code Administrator will, with the Authority’s approval, apply to the Authority for a revision or revisions to the Proposed Implementation Date in the Grid Code Modification Report in respect of such Grid Code Modification Proposal as necessary such that if such Grid Code Modification Proposal were to be approved following such Legal Challenge the Proposed Implementation Date...
would be achievable.

(f) Prior to making any request to the Authority for any revision pursuant to GR.3.2(d) (including where it is necessary as a result of a Legal Challenge) or GR.3.2(e) the Code Administrator shall consult on the revision with Users and such other person who may properly be considered to have an appropriate interest in it in accordance with GR.21.2 and GR.21.8. The request to the Authority shall contain copies of (and a summary of) all written representations or objections made by consultees during the consultation period.

GR.3.3 Duties of Panel Members

(a) A person appointed as a Panel Member, or an Alternate Member, by Users under GR.3.1 or GR.7.2, by the Authority under GR.4.3 and the person appointed as Panel Chairperson under GR.4.1, and each of their alternates when acting in that capacity:

(i) shall act impartially and in accordance with the requirements of the Grid Code; and

(ii) shall not be representative of, and shall act without undue regard to the particular interests of the persons or body of persons by whom they were appointed as Panel Member and any Related Person from time to time.

(b) Such a person shall not be appointed as a Panel Member or an Alternate Member (as the case may be) unless they shall have first:

(i) confirmed in writing to the Code Administrator for the benefit of all Users that they agree to act as a Panel Member or Alternate Member in accordance with the Grid Code and acknowledges the requirements of GR.3.3 (a) and GR.3.3(c);

(ii) where that person is employed, provided to the Panel Secretary a letter from their employer agreeing that they may act as Panel Member or Alternate Member, and that the requirement in GR.3.3(a)(ii) shall prevail over their duties as an employee.

(c) A Panel Member or Alternate Member shall, at the time of appointment and upon any change in such interests, disclose (in writing) to the Panel Secretary any such interests (in relation to the Grid Code) as are referred to in GR.3.3(a)(ii).

(d) Upon a change in employment of a Panel Member or Alternate Member, they shall so notify the Panel Secretary and shall endeavour to obtain from their new employer and provide to the Panel Secretary a letter in the terms required in GR.3.3(b)(ii); and they shall be removed from office if they do not do so within a period of sixty (60) days after such change in employment.

GR.4 APPOINTMENT OF PANEL MEMBERS

GR.4.1 Panel Chairperson

(a) The Panel Chairperson shall be a person appointed (or re-appointed) by The Company, having particular regard to the views of the Grid Code Review Panel, and shall act independently of The Company.

(b) A person shall be appointed or re-appointed as the Panel Chairperson where the Authority has approved such appointment or reappointment and The Company has given notice to the Panel Secretary of such appointment, with effect from the date of such notice or (if later) with effect from the date specified in such notice.

GR.4.2 Other Panel Members:

(a) the Network Operators, Suppliers, Onshore Transmission Licensees, Offshore
Transmission Licensees and Generators may appoint Panel Members by election in accordance with Annex GR.A.

(b) The Citizens Advice or the Citizens Advice Scotland may appoint one person as a Panel Member representing customers by giving notice of such appointment to the Panel Secretary, and may remove and re-appoint by notice.

(c) The Company shall appoint the The Company representative referred to at GR.3.1.2(c)(i) and shall give notice of the identity of such person to the Panel Secretary, and may remove and re-appoint by notice to the Panel Secretary.

(d) The BSC Panel shall appoint a representative to be the member of the Grid Code Review Panel referred to at GR.3.1.2(c) (iii) and shall give notice of the identity of such person to the Panel Secretary, and may remove and re-appoint by notice to the Panel Secretary.

GR.4.3. The Authority shall from time to time notify the Panel Secretary of the identity of the Authority representative referred to at GR.3.1.2(b)(ii).

GR.4.4 Appointment of Further Member:

(a) If in the opinion of the Authority there is a class or category of person (whether or not a User) who have interests in respect of the Grid Code but whose interests:

   (i) are not reflected in the composition of Panel Members for the time being appointed; but

   (ii) would be so reflected if a particular person was appointed as an additional Panel Member, then the Authority may at any time appoint (or re-appoint) that person as a Panel Member by giving notice of such appointment to the Panel Secretary but in no event shall the Authority be able to appoint more than one person so that there could be more than one such Panel Member.

(b) A person appointed as a Panel Member pursuant to this GR.4.4 shall remain appointed, subject to GR.5 and GR.6, notwithstanding that the conditions by virtue of which they were appointed (for example that the interests they reflect are otherwise reflected) may cease to be satisfied.

GR.4.5 Natural Person

No person other than an individual shall be appointed a Panel Member or their alternate.

GR.5 TERM OF OFFICE

The term of office of a Panel Member, the Panel Chairperson and Alternate Members shall be a period expiring on 31 December every second year. A Panel Member, the Panel Chairperson and Alternate Member shall be eligible for reappointment on expiry of their term of office.

GR.6 REMOVAL FROM OFFICE

GR.6.1 A person shall cease to hold office as the Panel Chairperson, a Panel Member or an Alternate Member:

   (a) upon expiry of their term of office unless re-appointed;

   (b) if they:

      (i) resign from office by notice delivered to the Panel Secretary;

      (ii) become bankrupt or makes any arrangement or composition with their creditors generally;

      (iii) are or may be suffering from a mental disorder and either are admitted to hospital in pursuance of an application under the Mental Health Act 1983 or the Mental Health (Scotland) Act 1960 or an order is made by a court having jurisdiction in matters concerning mental disorder for their detention or for the appointment of a
receiver, curator bonis or other person with respect to their property or affairs;
(iv) become prohibited by law from being a director of a company under the Companies Act 1985;
(v) die; or
(vi) are convicted on an indictable offence; or

(c) as provided for in GR.3.3(d);

(d) if the Grid Code Review Panel resolves (and the Authority does not veto such resolution by notice in writing to the Panel Secretary within fifteen (15) Business Days) that they should cease to hold office on grounds of their serious misconduct;

(e) if the Grid Code Review Panel resolves (and the Authority does not veto such resolution by notice in writing to the Panel Secretary within fifteen (15) Business Days) that they should cease to hold office due to a change in employer notwithstanding compliance with GR.3.3(d).

GR.6.2 A Grid Code Review Panel resolution under GR.6.1(d) or (e) shall, notwithstanding any other paragraph, require the vote in favour of at least all Panel Members less one (other than the Panel Member or Alternate Member who is the subject of such resolution) and for these purposes an abstention shall count as a vote cast in favour of the resolution. A copy of any such resolution shall forthwith be sent to the Authority by the Panel Secretary.

GR.6.3 A person shall not qualify for appointment as a Panel Member or Alternate Member if at the time of the proposed appointment they would be required by the above to cease to hold that office.

GR.6.4 The Panel Secretary shall give prompt notice to The Company, all Panel Members, all Users and the Authority of the appointment or re-appointment of any Panel Member or Alternate Member or of any Panel Member or Alternate Member ceasing to hold office and publication on the Website and (where relevant details are supplied to the Panel Secretary) despatch by electronic mail shall fulfil this obligation.

GR.7 ALTERNATES

GR.7.1 Alternate: Panel Chairperson

The Panel Chairperson shall preside at every meeting of the Grid Code Review Panel at which they are present. If they are unable to be present at a meeting, they may appoint an alternate (who shall be a senior employee of The Company) to act as the Panel Chairperson, who may or may not be a Panel Member. If neither the Panel Chairperson nor their alternate is present at the meeting within half an hour of the time appointed for holding the meeting, the Panel Members present may appoint one of their number to be the chairperson of the meeting.

GR.7.2 Alternate(s): other Panel Members

(a) At the same time that the parties entitled to vote in the relevant election appoint Elected Panel Members under GR.4.2(a), they shall appoint the following Alternate Members:
   (i) one alternate representative of the Suppliers;
   (ii) one alternate representative of the Onshore Transmission Licensees;
   (iii) one alternate representative of the Offshore Transmission Licensees; and
   (iv) two alternate representatives of the Generators.

In the event that the election process fails to appoint an Alternate Member for any of the Elected Panel Members, each Elected Panel Member shall be entitled (but not obligated) to each at their own discretion nominate their own Alternate Member.

(b) Any Panel Member that is not an Elected Panel Member shall be entitled (but not obligated) to each at their own discretion nominate their own Alternate Member.

(c) A Panel Member shall give notice to the Panel Secretary in the event it will be represented by an Alternate Member for any one Grid Code Review Panel meeting.
(d) Where a Panel Member has nominated an Alternate Member in accordance with GR.7.2(a) or (b), they may remove such Alternate Member, by giving notice of such removal, and any nomination of a different Alternate Member, to the Panel Secretary. A Panel Member may not choose as their Alternate Member: any party who is already acting as an Alternate Member for another Panel Member; or another Panel Member.

(e) All information to be sent by the Panel Secretary to Panel Members pursuant to these Governance Rules shall also be sent by the Panel Secretary to each Alternate Member by electronic mail (where relevant details shall have been provided by each Alternate Member).

GR.7.3 Alternates: General Provisions

(a) The appointment or removal by a Panel Member of an Alternate Member shall be effective from the time when such notice is given to the Panel Secretary or (if later) the time specified in such notice.

(b) The Panel Secretary shall promptly notify all Panel Members and Users of appointment or removal by any Panel Member of any alternate and publication on the Website and (where relevant details have been provided to the Panel Secretary) despatch by electronic mail shall fulfil this obligation.

GR.7.4 Alternates: Rights, Cessation and References

(a) Where the Panel Chairperson or a Panel Member has appointed an alternate:

(i) the alternate shall be entitled:
   i. unless the appointing Panel Member shall otherwise notify the Panel Secretary, to receive notices of meetings of the Grid Code Review Panel;
   ii. to attend, speak and vote at any meeting of the Grid Code Review Panel at which the Panel Member by whom they were appointed is not present, and at such meeting to exercise and discharge all of the functions, duties and powers of such Panel Member;

(ii) the Alternate Member shall have the same voting rights the Panel Member in whose place they are attending;

(iii) GR.8, GR.9, GR.10, GR.11 and GR.12 shall apply to the Alternate Member as if they were the appointing Panel Member and a reference to a Panel Member elsewhere in the Grid Code shall, unless the context otherwise requires, include their duly appointed Alternate Member.

(iv) for the avoidance of doubt, the appointing Panel Member shall not enjoy any of the rights transferred to the Alternate Member at any meeting at which, or in relation to any matter on which, the Alternate Member acts on their behalf.

(b) A person appointed as an Alternate Member shall automatically cease to be such Alternate Member:

(i) if the appointing Panel Member ceases to be a Panel Member;
(ii) if any of the circumstances in GR.6.1(b) applies in relation to such person, but, in the case of a person elected as an Alternate Member, they shall continue to be an Alternate Member available for appointment under GR.7.2.

GR.8 MEETINGS

GR.8.1 Meetings of the Grid Code Review Panel shall be held at regular intervals and at least every 2 months at such time and such place as the Grid Code Review Panel shall decide.
GR.8.2 A regular meeting of the Grid Code Review Panel may be cancelled if:

(a) the Panel Chairperson considers, having due regard to the lack of business in the agenda, that there is insufficient business for the Grid Code Review Panel to conduct and requests the Panel Secretary to cancel the meeting;

(b) the Panel Secretary notifies all Panel Members, not less than five (5) Business Days before the date for which the meeting is to be convened, of the proposal to cancel the meeting; and

(c) by the time three (3) Business Days before the date for which the meeting is or is to be convened, no Panel Member has notified the Panel Secretary that they object to such cancellation.

GR.8.3 If any Panel Member wishes, acting reasonably, to hold a special meeting (in addition to regular meetings under GR.8.1) of the Grid Code Review Panel:

(a) they shall request the Panel Secretary to convene such a meeting and inform the Panel Secretary of the matters to be discussed at the meeting;

(b) the Panel Secretary shall promptly convene the special meeting for a day as soon as practicable but not less than five (5) Business Days after such request.

GR.8.4 Any meeting of the Grid Code Review Panel shall be convened by the Panel Secretary by notice (which will be given by electronic mail if the relevant details are supplied to the Panel Secretary) to each Panel Member (and to the Authority):

(a) setting out the date, time and place of the meeting and (unless the Grid Code Review Panel has otherwise decided) given at least five (5) Business Days before the date of the meeting;

(b) accompanied by an agenda of the matters for consideration at the meeting and any supporting papers available to the Panel Secretary at the time the notice is given (and the Panel Secretary shall circulate to Panel Members any late papers as and when they are received by them).

GR.8.5 The Panel Secretary shall send a copy of the notice convening a meeting of the Grid Code Review Panel, and the agenda and papers accompanying the notice, to the Panel Members and Alternate Members, and publication on the Website and despatch by electronic mail (if the relevant details are supplied to the Panel Secretary) shall fulfil this obligation.

GR.8.6 Any Panel Member (or, at the Panel Member's request, the Panel Secretary) may notify matters for consideration at a meeting of the Grid Code Review Panel in addition to those notified by the Panel Secretary under GR.8.4 by notice to all Panel Members and persons entitled to receive notice under GR.8.5, not less than three (3) Business Days before the date of the meeting.

GR.8.7 The proceedings of a meeting of the Grid Code Review Panel shall not be invalidated by the accidental omission to give or send notice of the meeting or a copy thereof or any of the accompanying agenda or papers to, or failure to receive the same by, any person entitled to receive such notice, copy, agenda or paper.

GR.8.8 A meeting of the Grid Code Review Panel may consist of a conference between Panel Members who are not all in one place but who are able (by telephone or otherwise) to speak to each of the others and to be heard by each of the others simultaneously.

GR.8.9 With the consent of all Panel Members (whether obtained before, at or after any such meeting) the requirements of this GR.8 as to the manner in and notice on which a meeting of the Grid Code Review Panel is convened may be waived or modified provided that no meeting of the Grid Code Review Panel shall be held unless notice of the meeting and its agenda has been sent to the persons entitled to receive the same under GR.8.5 at least 24 hours before the time of the meeting.
GR.8.10 Subject to GR.8.11, no matter shall be resolved at a meeting of the Grid Code Review Panel unless such matter was contained in the agenda accompanying the Panel Secretary’s notice under GR.8.4 or was notified in accordance with GR.8.6.

GR.8.11 Where:

(a) any matter (not contained in the agenda and not notified pursuant to GR.8.4 and GR.8.6) is put before a meeting of the Grid Code Review Panel, and

(b) in the opinion of the Grid Code Review Panel it is necessary (in view of the urgency of the matter) that the Grid Code Review Panel resolve upon such matter at the meeting, the Grid Code Review Panel may so resolve upon such matter, and the Grid Code Review Panel shall also determine at such meeting whether the decision of the Grid Code Review Panel in relation to such matter should stand until the following meeting of the Grid Code Review Panel, in which case (at such following meeting) the decision shall be reviewed and confirmed or (but not with effect earlier than that meeting, and only so far as the consequences of such revocation do not make implementation of the Grid Code or compliance by Users with it impracticable) revoked.

GR.9 PROCEEDINGS AT MEETINGS

GR.9.1 Subject as provided in the Grid Code, the Grid Code Review Panel may regulate the conduct of and adjourn and reconvene its meetings as it sees fit.

GR.9.2 Meetings of the Grid Code Review Panel shall be open to attendance by a representative of any User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice or the Citizens Advice Scotland and any person invited by the Panel Chairperson and/or any other Panel Member.

GR.9.3 The Panel Chairperson and any other Panel Member may invite any person invited by them under GR.9.2, and/or any attending representative of a User, to speak at the meeting (but such person shall have no vote).

GR.9.4 As soon as practicable after each meeting of the Grid Code Review Panel, the Panel Secretary shall prepare and send (by electronic mail or otherwise) to Panel Members the minutes of such meeting, which shall be (subject to GR.9.5) approved (or amended and approved) at the next meeting of the Grid Code Review Panel after they were so sent, and when approved (excluding any matter which the Grid Code Review Panel decided was not appropriate for such publication) shall be placed on the Website.

GR.9.5 If, following the circulation of minutes (as referred to in GR.9.4), the meeting of the Grid Code Review Panel at which they were to be approved is cancelled pursuant to GR.8.2, such minutes (including any proposed changes thereto which have already been received) shall be recirculated with the notification of the cancellation of the meeting of the Grid Code Review Panel. Panel Members shall confirm their approval of such minutes to the Panel Secretary (by electronic mail) no later than five (5) Business Days following such minutes being re-circulated. If no suggested amendments are received within such five (5) Business Days period, the minutes will be deemed to have been approved. If the minutes are approved, or deemed to have been approved, (excluding any matter which the Grid Code Review Panel decided was not appropriate for such publication) they shall be placed on the Website. If suggested amendments are received within such five (5) Business Days period, the minutes shall remain unapproved and the process for approval (or amendment and approval) of such minutes at the next meeting of the Grid Code Review Panel, as described in GR.9.4, shall be followed.

GR.10 QUORUM

GR.10.1 No business shall be transacted at any meeting of the Grid Code Review Panel unless a quorum is present throughout the meeting.

GR.10.2 Subject to GR.10.4, a quorum shall be 6 Panel Members who have a vote present
(subject to GR.8.8) in person or by their alternates, of whom at least one shall be appointed by The Company. Where a Panel Member is represented by an Alternate Member, that Alternate Member cannot represent any other Panel Member at the same meeting.

GR.10.3 If within half an hour after the time for which the meeting of the Grid Code Review Panel has been convened a quorum is not present (and provided the Panel Secretary has not been notified by Panel Members that they have been delayed and are expected to arrive within a reasonable time):

(a) the meeting shall be adjourned to the same day in the following week (or, if that day is not a Business Day the next Business Day following such day) at the same time;
(b) the Panel Secretary shall give notice of the adjourned meeting as far as practicable in accordance with GR.8.

GR.10.4 If at the adjourned meeting there is not a quorum present within half an hour after the time for which the meeting was convened, those present shall be a quorum.

GR.11 VOTING

GR.11.1 At any meeting of the Grid Code Review Panel any matter to be decided which shall include the Grid Code Review Panel Recommendation Vote shall be put to a vote of those Panel Members entitled to vote in accordance with these Governance Rules upon the request of the Panel Chairperson or any Panel Member.

GR.11.2 Subject to GR.11.4, in deciding any matter at any meeting of the Grid Code Review Panel each Panel Member other than the Panel Chairperson shall cast one vote.

GR.11.3 Except as otherwise expressly provided in the Grid Code, and in particular GR.6.2, any matter to be decided at any meeting of the Grid Code Review Panel shall be decided by simple majority of the votes cast at the meeting (an abstention shall not be counted as a cast vote).

GR.11.4 The Panel Chairperson shall not cast a vote as a Panel Member but shall have a casting vote on any matter where votes are otherwise cast equally in favour of and against the relevant motion. Where the vote is in respect of a Grid Code Modification Proposal the Panel Chairperson may only use such casting vote to vote against such Grid Code Modification Proposal. The Panel Chairperson will have a free vote in respect of any other vote. Where any person other than the actual Panel Chairperson is acting as chairperson they shall not have a casting vote.

GR.11.5 Any resolution in writing signed by or on behalf of all Panel Members shall be valid and effectual as if it had been passed at a duly convened and quorate meeting of the Grid Code Review Panel. Such a resolution may consist of several instruments in like form signed by or on behalf of one or more Panel Members.

GR.12 PROTECTIONS FOR PANEL MEMBERS

GR.12.1 Subject to GR.12.2 all CUSC Parties shall jointly and severally indemnify and keep indemnified each Panel Member, the Panel Secretary and each member of a Workgroup (“Indemnified Persons”) in respect of all costs (including legal costs), expenses, damages and other liabilities properly incurred or suffered by such Indemnified Persons when acting in or in connection with their office under the Grid Code, or in what they in good faith believe to be the proper exercise and discharge of the powers, duties, functions and discretions of that office in accordance with the Grid Code, and all claims, demands and proceedings in connection therewith other than any such costs, expenses, damages or other liabilities incurred or suffered as a result of the wilful default or bad faith of such Indemnified Person.

GR.12.2 The indemnity provided in GR.12.1 shall not extend to costs and expenses incurred in the ordinary conduct of being a Panel Member or Panel Secretary, or member of a Workgroup including, without limitation, accommodation costs and travel costs or any
remuneration for their services to the **Grid Code Review Panel** or **Workgroup**.

**GR.12.3** The **Users** agree that no Indemnified Person shall be liable for anything done when acting properly in or in connection with their office under the **Grid Code**, or anything done in what they in good faith believe to be the proper exercise and discharge of the powers, duties, functions and discretions of that office in accordance with the **Grid Code**. Each **CUSIC Party** hereby irrevocably and unconditionally waives any such liability of any Indemnified Person and any rights, remedies and claims against any Indemnified Person in respect thereof.

**GR.12.4** Without prejudice to GR.12.2, nothing in GR.12.3 shall exclude or limit the liability of an Indemnified Person for death or personal injury resulting from the negligence of such Indemnified Person.

**PART C**

**GR.13** **GRID CODE MODIFICATION REGISTER**

**GR.13.1** The **Code Administrator** shall establish and maintain a register ("**Grid Code Modification Register**") in a form as may be agreed with the **Authority** from time to time, which shall record the matters set out in GR.13.3.

**GR.13.2** The purpose of the **Grid Code Modification Register** shall be to assist the **Grid Code Review Panel** and to enable the **Grid Code Review Panel**, **Users** and any other persons who may be interested to be reasonably informed of the progress of **Grid Code Modification Proposals** and **Approved Modifications** from time to time.

**GR.13.3** The **Grid Code Modification Register** shall record in respect of current outstanding **Grid Code Review Panel** business:

(a) details of each **Grid Code Modification Proposal** (including the name of the **Proposer**, the date of the **Grid Code Modification Proposal** and a brief description of the **Grid Code Modification Proposal**);

(b) whether such **Grid Code Modification Proposal** is an **Urgent Modification**;

(c) the current status and progress of each **Grid Code Modification Proposal**, if appropriate the anticipated date for reporting to the **Authority** in respect thereof, and whether it has been withdrawn, rejected or implemented for a period of three (3) months after such withdrawal, rejection or implementation or such longer period as the **Authority** may determine;

(d) the current status and progress of each **Approved Modification**, each **Approved Grid Code Self-Governance Proposal**, and each **Approved Fast Track Proposal**; and

(e) such other matters as the **Grid Code Review Panel** may consider appropriate from time to time to achieve the purpose of GR.13.2.

**GR.13.4** The **Grid Code Modification Register** (as updated from time to time and indicating the revisions since the previous issue) shall be published on the **Website** or (in the absence, for whatever reason, of the **Website**) in such other manner and with such frequency (being not less than once per month) as the **Code Administrator** may decide in order to bring it to the attention of the **Grid Code Review Panel**, **Users** and other persons who may be interested.

**GR.14** **CHANGE CO-ORDINATION**

**GR.14.1** The **Code Administrator** shall establish (and, where appropriate, revise from time to time) joint working arrangements for change co-ordination with each **Core Industry Document Owner** and with the **STC Modification Panel** to facilitate the identification, co-ordination, making and implementation of change to **Core Industry Documents** and the **STC** consequent on a **Grid Code Modification Proposal**, including, but not limited
to, changes that are appropriate in order to avoid conflict or inconsistency as between the Grid Code and any Core Industry Document and the STC, in a full and timely manner.

GR.14.2 The working arrangements referred to in GR.14.1 shall be such as to enable the consideration, development and evaluation of Grid Code Modification Proposals, and the implementation of Approved Modifications, to proceed in a full and timely manner and enable changes to Core Industry Documents and the STC consequent on an amendment to be made and given effect wherever possible (subject to any necessary consent of the Authority) at the same time as such Grid Code Modification Proposal is made and given effect.

GR.15 GRID CODE MODIFICATION PROPOSALS

GR.15.1 A proposal to modify the Grid Code may be made:

(a) by any User; any Authorised Electricity Operator liable to be materially affected by such a proposal; the Citizens Advice or the Citizens Advice Scotland;

(b) under GR.25.5, by the Grid Code Review Panel; or

(c) by the Authority:

(i) following publication of its Significant Code Review conclusions; or
(ii) under GR.17; or
(iii) in order to comply with or implement the Electricity Regulation and/or any relevant Legally Binding Decisions of the European Commission and/or the Agency.

GR.15.2 A Standard Modification shall follow the procedure set out in GR.18 to GR.22.

GR.15.3 A Grid Code Modification Proposal shall be submitted in writing to the Panel Secretary and, subject to the provisions of GR.15.4 below, shall contain the following information in relation to such proposal:

(a) the name of the Proposer;

(b) the name of the representative of the Proposer who shall represent the Proposer in person for the purposes of this GR.15;

(c) a description (in reasonable but not excessive detail) of the issue or defect which the proposed modification seeks to address;

(d) a description (in reasonable but not excessive detail) of the proposed modification and of its nature and purpose;

(e) where possible, an indication of those parts of the Grid Code which would require amendment in order to give effect to (and/or would otherwise be affected by) the proposed modification and an indication of the nature of those amendments or effects;

(f) the reasons why the Proposer believes that the proposed modification would better facilitate achievement of the Grid Code Objectives as compared with the current version of the Grid Code together with background information in support thereof;

(g) the reasoned opinion of the Proposer as to why the proposed modification should not fall within a current Significant Code Review, whether the proposed modification should be treated as a Self-Governance Modification or whether the proposed modification fails to meet the Self-Governance Criteria and as a result should proceed along the Standard Modification route;

(h) the reasoned opinion of the Proposer as to whether that impact is likely to be material and if so an assessment of the quantifiable impact of the proposed modification on greenhouse gas emissions, to be conducted in accordance with such
current guidance on the treatment of carbon costs and evaluation of the greenhouse
gas emissions as may be issued by the Authority from time to time;

(i) where possible, an indication of the impact of the proposed modification on Core
Industry Documents and the STC;

(j) where possible, an indication of the impact of the proposed modification on relevant
computer systems and processes used by Users.

(k) whether or not (and to the extent) that in the proposer’s view the Grid Code
Modification Proposal constitutes an amendment to the Regulated Sections of the
Grid Code.

GR.15.4 The Proposer of a Grid Code Fast Track Proposal is not required to provide the items
referenced at GR.15.3 (f) – (j) inclusive, unless either:

(a) the Grid Code Review Panel has, pursuant to GR.26.5 or GR.26.6, not agreed
unanimously that the Grid Code Fast Track Proposal meets the Fast Track
Criteria, or has not unanimously approved the Grid Code Fast Track Proposal; or

(b) there has been an objection to the Approved Fast Track Proposal pursuant to
GR.26.12, whereupon the Proposer shall be entitled to provide the additional
information required pursuant to GR.15.3 for a Grid Code Modification Proposal
within 28 days of the Panel Secretary’s request. Where the Proposer fails to provide
the additional information in accordance with such timescales, the Panel Secretary
may reject such proposal in accordance with GR.15.5.

GR.15.5 If a proposal fails in any material respect to provide the information in GR.15.3 (excluding (e), (i)
and (j) thereof), the Panel Secretary may reject such proposal provided that:

(a) the Panel Secretary shall furnish the Proposer with the reasons for such rejection;

(b) the Panel Secretary shall report such rejection to the Grid Code Review Panel at
the next Grid Code Review Panel meeting, with details of the reasons;

(c) if the Grid Code Review Panel decides or the Authority directs to reverse the Panel
Secretary’s decision to refuse the submission, the Panel Secretary shall notify the
Proposer accordingly and the proposal shall be dealt with in accordance with these
Governance Rules;

(d) nothing in these Governance Rules shall prevent a Proposer from submitting a
revised proposal in compliance with the requirements of GR.15.3 in respect of the
same subject-matter.

GR.15.6 Without prejudice to the development of a Workgroup Alternative Grid Code Modification(s)
pursuant to GR.20.13 and GR.20.18, the Grid Code Review Panel shall direct in the case of
(a), and may direct in the case of (b), the Panel Secretary to reject a proposal pursuant to
GR.15, other than a proposal submitted by The Company pursuant to a direction issued by the
Authority following a Significant Code Review in accordance with GR.16.4, or an Authority
Led modification, if and to the extent that such proposal has, in the opinion of the Grid Code
Review Panel, substantially the same effect as:

(a) a Pending Grid Code Modification Proposal; or

(b) a Rejected Grid Code Modification Proposal, where such proposal is made at any
time within two (2) months after the decision of the Authority not to direct The
Company to modify the Grid Code pursuant to the Transmission Licence in the
manner set out in such Grid Code Modification Proposal, and the Panel Secretary
shall notify the Proposer accordingly.

GR.15.7 Promptly upon receipt of a Grid Code Modification Proposal, the Panel Secretary
shall:
(a) allocate a unique reference number to the Grid Code Modification Proposal;

(b) enter details of the Grid Code Modification Proposal on the Grid Code Modification Register;

(c) reserve the right to modify the title or summary of the Grid Code Modification Proposal to better reflect the content or intent of the proposal. If such changes are made these shall be agreed by the Proposer, or where this cannot be achieved by the Grid Code Review Panel at their next meeting; and

(d) note whether in the proposer’s view the Grid Code Modification Proposal constitutes an amendment to the Regulated Sections of the Grid Code.

GR.15.8 Subject to GR.8.6 and GR.26, where the Grid Code Modification Proposal is received more than ten (10) Business Days prior to the next Grid Code Review Panel meeting, the Panel Secretary shall place the Grid Code Modification Proposal on the agenda of the next Grid Code Review Panel meeting and otherwise shall place it on the agenda of the next succeeding Grid Code Review Panel meeting.

GR.15.9 It shall be a condition to the right to make a proposal to modify the Grid Code under this GR.15 that the Proposer:

(a) grants a non-exclusive royalty free licence to all Users who request the same covering all present and future rights, IPRs and moral rights it may have in such proposal (as regards use or application in Great Britain); and

(b) warrants that, to the best of its knowledge, information and belief, no other person has asserted to the Proposer that such person has any IPRs or normal rights or rights of confidence in such proposal, and, in making a proposal, a Proposer which is a Grid Code Party shall be deemed to have granted the licence and given the warranty in (a) and (b) above.

(c) The provisions of this GR.15.9 shall apply to any WG Consultation Alternative Request, and also to a Relevant Party supporting a Grid Code Modification Proposal in place of the original Proposer in accordance with GR.15.10 (a) for these purposes the term Proposer shall include any such Relevant Party or a person making such a WG Consultation Alternative Request.

GR.15.10 Subject to GR.16.1, which deals with the withdrawal of a Grid Code Modification Proposal made pursuant to a direction following a Significant Code Review, a Proposer may withdraw their support for a Standard Modification by notice to the Panel Secretary at any time prior to the Grid Code Review Panel Recommendation Vote undertaken in relation to that Standard Modification pursuant to GR.22.4, and a Proposer may withdraw their support for a Grid Code Modification Proposal that meets the Self-Governance Criteria by notice to the Panel Secretary at any time prior to the Grid Code Review Panel Self-Governance Vote undertaken in relation to that Grid Code Modification Proposal pursuant to GR.24.9, and a Proposer may withdraw their support for a Grid Code Fast Track Proposal by notice to the Panel Secretary at any time prior to the Panel’s vote on whether to approve the Grid Code Fast Track Proposal pursuant to GR.26 in which case the Panel Secretary shall forthwith:

(a) notify those parties specified in GR.15.1 as relevant in relation to the Grid Code Modification Proposal in question (a “Relevant Party”) that they have been notified of the withdrawal of support by the Proposer by publication on the Website and (where relevant details are supplied) by electronic mail. A Relevant Party may within five (5) Business Days notify the Panel Secretary that it is prepared to support the Grid Code Modification Proposal in place of the original Proposer. If such notice is received, the name of such Relevant Party shall replace that of the original Proposer as the Proposer, and the Grid Code Modification Proposal shall continue. If more than one notice is received, the first received shall be utilised;
(b) if no notice of support is received under (a), the matter shall be discussed at the next Grid Code Review Panel meeting. If the Grid Code Review Panel so agrees, it may notify Relevant Parties that the Grid Code Modification Proposal is to be withdrawn, and a further period of five (5) Business Days shall be given for support to be indicated by way of notice;

(c) if no notice of support is received under (a) or (b), the Grid Code Modification Proposal shall be marked as withdrawn on the Grid Code Modification Register; Code Administrator as Critical Friend.

GR.15.11 The Code Administrator shall provide assistance insofar as is reasonably practicable and on reasonable request to parties with an interest in the Grid Code Modification process that request it in relation to the Grid Code, as provided for in the Code Administration Code of Practice, including, but not limited to, assistance with:

(a) Drafting a Grid Code Modification Proposal;

(b) Understanding the operation of the Grid Code;

(c) Their involvement in, and representation during, the Grid Code Modification Proposal process (including but not limited to Grid Code Review Panel, and/or Workgroup meetings) as required or as described in the Code Administration Code of Practice;

(d) Helping the Proposer and Workgroup by producing draft legal text once a clear solution has been developed to support the discussion and understanding of a Grid Code Modification Proposal; and

(e) accessing information relating to Grid Code Modification Proposals and/or Approved Modifications.

GR.16 SIGNIFICANT CODE REVIEW

GR.16.1 If any party specified under GR.15.1 (other than the Authority) makes a Grid Code Modification Proposal during a Significant Code Review Phase, unless exempted by the Authority or unless GR.16.4(b) applies, the Grid Code Review Panel shall assess whether the Grid Code Modification Proposal falls within the scope of a Significant Code Review and the applicability of the exceptions set out in GR.16.4 and shall notify the Authority of its assessment, its reasons for that assessment and any representations received in relation to it as soon as practicable.

GR.16.2 The Grid Code Review Panel shall proceed with the Grid Code Modification Proposal made during a Significant Code Review Phase in accordance with GR.18 (notwithstanding any consultation undertaken pursuant to GR.16.5 and its outcome), unless directed otherwise by the Authority pursuant to GR.16.3.

GR.16.3 Subject to GR.16.4, the Authority may at any time direct that a Grid Code Modification Proposal made during a Significant Code Review Phase falls within the scope of a Significant Code Review and must not be made during the Significant Code Review Phase. If so directed, the Grid Code Review Panel will not proceed with that Grid Code Modification Proposal, and the Proposer shall decide whether the Grid Code Modification Proposal shall be withdrawn or suspended until the end of the Significant Code Review Phase. If the Proposer fails to indicate its decision whether to withdraw or suspend the Grid Code Modification Proposal within twenty-eight (28) days of the Authority’s direction, it shall be deemed to be suspended. If the Grid Code Modification Proposal is suspended, it shall be open to the Proposer at the end of the Significant Code Review Phase to indicate to the Grid Code Review Panel that it wishes that Grid Code Modification Proposal to proceed, and it shall be considered and taken forward in the manner decided upon by the Grid Code Review Panel at the next meeting, and it is open to the Grid Code Review Panel to take into account any work previously undertaken in respect of that Grid Code Modification Proposal. If the Proposer makes no indication to the Grid Code Review Panel within twenty-eight (28) days of the end of the Significant Code Review Phase as to whether or not it wishes the
Grid Code Modification Proposal to proceed, it shall be deemed to be withdrawn.

GR.16.4 A Grid Code Modification Proposal that falls within the scope of a Significant Code Review may be made where:

(a) the Authority so determines, having taken into account (among other things) the urgency of the subject matter of the Grid Code Modification Proposal; or

(b) the Grid Code Modification Proposal is made by The Company pursuant to a direction from the Authority; or

(c) it is raised by the Authority pursuant to GR15.1(c)(i) who reasonably considers the Grid Code Modification Proposal to be necessary to comply with or implement the Electricity Regulation and/or any relevant Legally Binding Decisions of the European Commission and/or the Agency;

(d) it is raised by the Authority and is in respect of a Significant Code Review.

GR.16.5 Where a direction under GR.16.3 has not been issued, GR.16.4 does not apply and the Grid Code Review Panel considers that a Grid Code Modification Proposal made during a Significant Code Review Phase falls within the scope of a Significant Code Review, the Grid Code Review Panel may consult on its suitability as part of the Standard Modification route set out in GR.19, GR.20, GR.21 and GR.22.

GR.16.6 If, within twenty eight (28) days after the Authority has published its Significant Code Review conclusions:

(a) the Authority issues directions to The Company, including directions to The Company to make a Grid Code Modification Proposal, The Company shall comply with those directions and The Company and all Users shall treat the Significant Code Review Phase as ended on the date on which The Company makes a Grid Code Modification Proposal in accordance with the Authority’s directions;

(b) the Authority issues to the The Company a statement that no directions under sub-paragraph (a) will be issued in relation to a Grid Code Modification Proposal, The Company and all Users shall treat the Significant Code Review Phase as ended on the date of such statement;

(c) the Authority raises a Grid Code Modification Proposal in accordance with GR.15.1(c) or GR.17 The Company and all Users shall treat the Significant Code Review Phase as ended;

(d) the Authority issues a statement that it will continue work on the Significant Code Review, The Company and all Users shall treat the Significant Code Review Phase as continuing until it is brought to an end in accordance with GR.16.7;

(e) neither directions under sub-paragraph (a) nor a statement under sub-paragraphs (b) or (d) have been issued, nor a Grid Code Modification Proposal under sub-paragraph (c) has been made, the Significant Code Review Phase will be deemed to have ended. The Authority’s published conclusions and directions to The Company will not fetter any voting rights of the Panel Members or the procedures informing the Grid Code Modification Report.

GR.16.7 If the Authority issues a statement under GR.16.6(d) and/or a direction in accordance with GR.16.10, the Significant Code Review Phase will be deemed to have ended when:
(a) the **Authority** issues a statement that the **Significant Code Review Phase** has ended;

(b) one of the circumstances in sub-paragraphs GR.16.6(a) or (c) occurs (irrespective of whether such circumstance occurs within twenty-eight (28) days after the **Authority** has published its **Significant Code Review** conclusions); or

(c) the **Authority** makes a decision consenting, or otherwise, to an **Authority-Led Modification** following the **Grid Code Review Panel**’s submission of its **Grid Code Modification Report**.

GR.16.8

Any **Grid Code Modification Proposal** in respect of a **Significant Code Review** that is not an **Authority-Led Modification** raised pursuant to GR.17 shall be treated as a **Standard Modification** and shall proceed through the process for **Standard Modifications** set out in GR.18, GR.19, GR.20, GR.21 and GR.22.

GR.16.9

The **Company** may not, without the prior consent of the **Authority**, withdraw a **Grid Code Modification Proposal** made pursuant to a direction issued by the **Authority** pursuant to GR.16.4(b)).

GR.16.10

Where a **Grid Code Modification Proposal** has been raised in accordance with GR.16.4(b) or GR.15.1(a), or by the **Authority** under GR.15.1(c) and it is in respect of a **Significant Code Review**, the **Authority** may issue a direction (a “backstop direction”), which requires such proposal(s) and any alternatives to be withdrawn and which causes the **Significant Code Review Phase** to recommence.

GR.17

**AUTHORITY LED MODIFICATIONS**

Power to develop a proposed modification

GR.17.1

The **Authority** may develop an **Authority-Led Modification** in respect of a **Significant Code Review**, in accordance with the procedures set out in this GR.17.

GR.17.2

An **Authority-led Modification** may be submitted where the **Significant Code Review Phase** is extended by a statement issued by the **Authority** as described in GR.16.6(d), or where a direction is issued under GR.16.10.

Authority-Led Modification Report

GR.17.3

The **Authority** may submit its proposed **Authority-Led Modification** to the **Code Administrator**, together with such supplemental information as the **Authority** considers appropriate.

GR.17.4

Upon receipt of the **Authority’s** proposal under GR.17.3, the **Code Administrator** shall prepare a written report on the proposal (the "**Authority-Led Modification Report**"). Where the **Code Administrator** does not reasonably believe the information provided by the **Authority** under 17.3 to be sufficient for it to prepare an **Authority-Led Modification Report** the **Code Administrator** will notify the **Authority** as soon as reasonably practical. The **Authority-Led Modification Report** must be consistent with the information provided by the **Authority** under GR.17.3, and shall:

(a) be addressed and delivered to the **Grid Code Review Panel**;

(b) set out the legal text of the proposed **Authority-Led Modification**;

(c) include a description of the proposed **Authority-Led Modification**;

(d) include a summary of the views (including any recommendations) from parties
consulted in respect of the proposed **Authority-Led Modification**;

(e) include an analysis of whether (and, if so, to what extent) the proposed **Authority-Led Modification** would better facilitate achievement of the **Grid Code Objective(s)** with a detailed explanation of the **Authority**’s reasons for its assessment, including, where the impact is likely to be material, an assessment of the quantifiable impact of the proposed **Authority-Led Modification** on greenhouse gas emissions, to be conducted in accordance with such current guidance on the treatment of carbon costs and evaluation of the greenhouse gas emissions as may be issued by the **Authority** from time to time, and providing a detailed explanation of the **Authority**’s reasons for that assessment;

(f) specify the proposed implementation timetable (including the **Proposed Implementation Date**);

(g) provide an assessment of:

- (i) the impact of the proposed **Authority-Led Modification** on the **Core Industry Documents** and the **STC**;
- (ii) the changes which would be required to the **Core Industry Documents** and the **STC** in order to give effect to the proposed **Authority-Led Modification**;
- (iii) the mechanism and likely timescale for the making of the changes referred to in (ii);
- (iv) the changes and/or developments which would be required to central computer systems and, if practicable, processes used in connection with the operation of arrangements established under the **Core Industry Documents** and the **STC**;
- (v) the mechanism and likely timescale for the making of the changes referred to in (iv);
- (vi) an estimate of the costs associated with making and delivering the changes referred to in (ii) and (iv), such costs are expected to relate to: for (ii) the costs of amending the **Core Industry Document(s)** and **STC** and for (iv) the costs of changes to computer systems and possibly processes which are established for the operation of the **Core Industry Documents** and the **STC**, together with an analysis and a summary of representations in relation to such matters, including any made by **Small Participants**, the **Citizens Advice** and the **Citizens Advice Scotland**;

(h) contain, to the extent such information is available to the **Code Administrator**, an assessment of the impact of the proposed **Authority-Led Modification** on **Users** in general (or classes of **Users**), including the changes which are likely to be required to their internal systems and processes and an estimate of the development, capital and operating costs associated with implementing the changes to the **Grid Code** and to **Core Industry Documents** and the **STC**;

(i) include copies of (and a summary of) all written representations or objections made by parties consulted by the **Authority** in respect of the proposed **Authority-Led Modification** and subsequently maintained; and

(j) have appended a copy of any impact assessment prepared by **Core Industry Document Owners** and the **STC** committee and the views and comments of the **Code Administrator** in respect thereof.

**GR.17.5** Where the **Authority-Led Modification Report** is received more than ten (10) **Business Days** prior to the next **Grid Code Review Panel** meeting, the **Panel Secretary** shall place the proposed **Authority-Led Modification** on the agenda of the next **Grid Code Review Panel** meeting and otherwise shall place it on the agenda of the next succeeding **Grid Code Review Panel** meeting.

**Grid Code Review Panel Decision**

**GR.17.6** In the case of **Authority-Led Modifications** **GR.22** shall apply, save for **GR.22.1** and **GR.22.2** and the **Authority-Led Modification Report** shall be used as the draft **Grid**.

GR.17.7 Where an Authority-Led Modification has been approved in accordance with Section GR.22, GR.25 (Implementation) shall apply.

GR.18 GRID CODE MODIFICATION PROPOSAL EVALUATION

GR.18.1 This GR.18 is subject to the Urgent Modification procedures set out in GR.23 and the Significant Code Review procedures set out in GR.16.

GR.18.2 A Grid Code Modification Proposal shall, subject to GR.15.8, be discussed by the Grid Code Review Panel at the next following Grid Code Review Panel meeting convened.

GR.18.3 The Proposer’s representative shall attend such Grid Code Review Panel meeting and the Grid Code Review Panel may invite the Proposer’s representative to present their Grid Code Modification Proposal to the Grid Code Review Panel.


GR.18.5 The Grid Code Review Panel shall follow the procedure set out in GR.24 in respect of any Modification that the Grid Code Review Panel considers meets the Self-Governance Criteria unless the Authority makes a direction in accordance with GR.24.2 and in such a case that Modification shall be a Standard Modification and shall follow the procedure set out in GR.19, GR.20, GR.21 and GR.22.

GR.18.6 Unless the Authority makes a direction in accordance with GR.24.4, a Modification that the Grid Code Review Panel considers does not meet the Self-Governance Criteria shall be a Standard Modification and shall follow the procedure set out in GR.19, GR.20, GR.21 and GR.22.


GR.18.9 The Grid Code Review Panel shall evaluate each Grid Code Modification Proposal and determine whether the Grid Code Modification Proposal constitutes an amendment to the Regulated Sections of the Grid Code and, if a change to the areas set out in Table 1 of the GR.B annex which details the Regulated Sections, its expected impact on the objectives of Retained EU Law (Commission Regulation (EU) 2017/2195) (and in the event of disagreement The Company’s view shall prevail).

GR.19 PANEL PROCEEDINGS

GR.19.1 (a) The Code Administrator and the Grid Code Review Panel shall together establish a timetable to apply for the Grid Code Modification Proposal process. That timetable must comply with any direction(s) issued by the Authority setting and/or amending a timetable in relation to a Grid Code Modification Proposal that is in the respect of a Significant Code Review.

(b) The Grid Code Review Panel shall establish the part of the timetable for the consideration by the Grid Code Review Panel and by a Workgroup (if any) which shall be no longer than six months unless in any case the particular circumstances of the Grid Code Modification Proposal (taking due account of its complexity, importance and urgency) justify an extension of such timetable, and provided the Authority, after receiving notice, does not object, taking into account all those issues.

(c) The Code Administrator shall establish the part of the timetable for the consultation
to be undertaken by the Code Administrator under these Governance Rules and separately the preparation of a Grid Code Modification Report to the Authority. Where the particular circumstances of the Grid Code Modification Proposal (taking due account of its complexity, importance and urgency) justify an extension of such timescales and provided the Authority, after receiving notice, does not object, taking into account all those issues, the Code Administrator may revise such part of the timetable.

(d) In setting such a timetable, the Grid Code Review Panel and the Code Administrator shall exercise their respective discretions such that, in respect of each Grid Code Modification Proposal, a Grid Code Modification Report may be submitted to the Authority as soon after the Grid Code Modification Proposal is made as is consistent with the proper evaluation of such Grid Code Modification Proposal, taking due account of its complexity, importance and urgency.

(e) Having regard to the complexity, importance and urgency of particular Grid Code Modification Proposals, the Grid Code Review Panel may determine the priority of Grid Code Modification Proposals and may (subject to any objection from the Authority taking into account all those issues) adjust the priority of the relevant Grid Code Modification Proposal accordingly.

GR.19.2

In relation to each Grid Code Modification Proposal, the Grid Code Review Panel shall determine at any meeting of the Grid Code Review Panel whether to:

(a) amalgamate the Grid Code Modification Proposal with any other Grid Code Modification Proposal;

(b) invite the Proposer to further develop their Grid Code Modification Proposal before presenting it to a subsequent meeting of the Grid Code Review Panel or to withdraw their modification proposal;

(c) establish a Workgroup of the Grid Code Review Panel, to consider the Grid Code Modification Proposal;

(d) review the evaluation made pursuant to GR.18.4, taking into account any new information received; or

(e) proceed directly to wider consultation (in which case the Proposer’s right to vary their Grid Code Modification Proposal shall lapse).

GR.19.3

The Grid Code Review Panel may decide to amalgamate a Grid Code Modification Proposal with one or more other Grid Code Modification Proposals where the subject-matter of such Grid Code Modification Proposals is sufficiently proximate to justify amalgamation on the grounds of efficiency and/or where such Grid Code Modification Proposals are logically dependent on each other. Such amalgamation may only occur with the consent of the Proposers of the respective Grid Code Modification Proposals. The Authority shall be entitled to direct that a Grid Code Modification Proposal is not amalgamated with one or more other Grid Code Modification Proposals.

GR.19.4

Without prejudice to each Proposer’s right to withdraw their Grid Code Modification Proposal prior to the amalgamation of their Grid Code Modification Proposal where Grid Code Modification Proposals are amalgamated pursuant to GR.19.3:

(a) such Grid Code Modification Proposals shall be treated as a single Grid Code Modification Proposal;

(b) references in these Governance Rules to a Grid Code Modification Proposal shall include and apply to a group of two or more Grid Code Modification Proposals so amalgamated; and

(c) the Proposers of each such Grid Code Modification Proposal shall cooperate in deciding which of them is to provide a representative for any Workgroup in respect of the amalgamated Grid Code Modification Proposal and, in default of agreement,
the Panel Chairperson shall nominate one of the Proposers for that purpose.

**GR.19.5**

In respect of any Grid Code Modification Proposal that the Grid Code Review Panel determines to proceed directly to wider consultation in accordance with GR.19.2, the Grid Code Review Panel, may at any time prior to the Grid Code Review Panel Recommendation Vote having taken place decide to establish a Workgroup of the Grid Code Review Panel and the provisions of GR.20 shall apply. In such case the Grid Code Review Panel shall be entitled to adjust the timetable referred to at GR.19.1(b) and the Code Administrator shall be entitled to adjust the timetable referred to at GR.19.1(c), provided that the Authority, after receiving notice, does not object.

**GR.19.6**

Where the Grid Code Review Panel according to GR.19.2(b) invites the Proposer to further develop their Grid Code Modification Proposal, on presenting this to a subsequent meeting of the Grid Code Review Panel, the Panel will determine a way forward from the options in GR.19.2 (a), (c), (d) and (e) or invite the Proposer to withdraw their modification proposal.

**GR.19.7**

Where the Grid Code Review Panel according to GR.19.2(b) or GR.19.6 invites the Proposer to further develop or withdraw their modification and this is declined, the Panel will determine a way forward from the options in GR.19.2 (a), (c), (d) or (e).

**GR.20**

**WORKGROUPS**

**GR.20.1**

If the Grid Code Review Panel has decided not to proceed directly to wider consultation (or where the provisions of GR.19.5, GR.23.10 or GR.25.5 apply), a Workgroup will be established by the Grid Code Review Panel to assist the Grid Code Review Panel in evaluating whether a Grid Code Modification Proposal better facilitates achieving the Grid Code Objectives and whether a Workgroup Alternative Grid Code Modification(s) would, as compared with the Grid Code Modification Proposal, better facilitate achieving the Grid Code Objectives in relation to the issue or defect identified in the Grid Code Modification Proposal.

**GR.20.2**

A single Workgroup may be responsible for the evaluation of more than one Grid Code Modification Proposal at the same time, but need not be so responsible.

**GR.20.3**

A Workgroup shall comprise at least five (5) persons (who may be Panel Members) selected by the Grid Code Review Panel from those nominated by Users, the Citizens Advice or the Citizens Advice Scotland for their relevant experience and/or expertise in the areas forming the subject-matter of the Grid Code Modification Proposal(s) to be considered by such Workgroup (and the Grid Code Review Panel shall ensure, as far as possible, that an appropriate cross-section of representation, experience and expertise is represented on such Workgroup) provided that there shall always be at least one member representing The Company and if, and only if, the Grid Code Review Panel is of the view that a Grid Code Modification Proposal is likely to have an impact on the STC, the Grid Code Review Panel may invite the STC committee to appoint a representative to become a member of the Workgroup. A representative of the Authority may attend any meeting of a Workgroup as an observer and may speak at such meeting.

**GR.20.4**

The Code Administrator shall in consultation with the Grid Code Review Panel appoint the chairperson of the Workgroup who shall act impartially and as an independent chairperson.

**GR.20.5**

No Workgroup or meeting of a Workgroup will be considered quorate with less than five (5) persons, not including the Code Administrator representative or the chairperson of the Workgroup. Where insufficient persons are nominated to a Workgroup for it to be quorate, the Code Administrator will report this to the next meeting of the Grid Code Review Panel. The Panel may:

(a) Request the Code Administrator to seek further nominations;

(b) Reconsider their decision on how to progress the Grid Code Modification Proposal
as allowed under GR.19.2; or

(c) Request that those parties that have nominated themselves to a Workgroup which is less than quorate should proceed as a Limited Membership Workgroup, subject to the following additional checks and balances:

(i) A Limited Membership Workgroup shall always hold a Workgroup Consultation in addition to the mandatory Code Administrator Consultation.

(ii) Prior to the Workgroup Consultation, a draft of this shall be circulated to the Grid Code Review Panel for five (5) days or another timescale as agreed by the Panel for approval.

(iii) At the same time as the Workgroup Consultation is initiated, the Code Administrator shall again formally seek nominations and if quoracy is not established then again seek advice from the Panel on how to proceed from the options set out in GR.20.5.

Where a Workgroup remains non-quorate, and with the permission of the Panel, a Limited Membership Workgroup may continue following a Workgroup Consultation as if it were a standard Workgroup.

GR.20.6

A Limited Membership Workgroup may at any point be instructed by the Authority to either:

(a) Stop work; or

(b) To provide a report on progress to the next meeting of the Grid Code Review Panel.

The Authority may also at any point instruct the Code Administrator to seek further nominations for membership.

GR.20.7

Where a specific meeting of an otherwise quorate Workgroup is not quorate, or where member(s) of a Limited Membership Workgroup are unable to attend a meeting:

(a) A member of the Workgroup unable to attend will be invited by the Code Administrator to send an alternate;

(b) All members will be invited to participate by telephone, webinar or other equivalent if not able to attend in person;

(c) A meeting may proceed as a Workgroup meeting as long as none of the members either present or absent raise an objection to this, however no voting can take place unless the Code Administrator has obtained enough votes to be quorate from members not in attendance or from all members of a Limited Membership Workgroup. This shall include where there has not been an opportunity to check with all Workgroup members to see if they have an objection (typically where a change of plans or circumstances has occurred too late to achieve this);

(d) If any Workgroup member objects to the progressing of a Workgroup without them, they must communicate this to the Code Administrator at least 24 hours before the meeting indicating that they will not be present and do not wish the meeting to take place. The Code Administrator will then endeavour to rearrange the meeting to accommodate such a member’s availability;

(e) Where a Workgroup member is repeatedly unavailable, as guidance on 3 consecutive occasions, and does not give permission for the Workgroup to proceed without them as in (d), under GR.20.7 the Grid Code Review Panel may choose to replace or remove them.

GR.20.8

The Grid Code Review Panel may add further members or the Workgroup chairperson may add or vary members to a Workgroup.
GR.20.9 The Grid Code Review Panel may (but shall not be obliged to) replace or remove any member or observer of a Workgroup appointed pursuant to GR.20.3 at any time if such member is unwilling or unable for whatever reason to fulfil that function and/or is deliberately and persistently disrupting or frustrating the work of the Workgroup.

GR.20.10 The Grid Code Review Panel shall determine the terms of reference of each Workgroup and may change those terms of reference from time to time as it sees fit.

GR.20.11 The terms of reference of a Workgroup must include provision in respect of the following matters:

(a) those areas of a Workgroup’s powers or activities which require the prior approval of the Grid Code Review Panel;

(b) the seeking of instructions, clarification or guidance from the Grid Code Review Panel, including on the suspension of a Workgroup Alternative Grid Code Modification(s) during a Significant Code Review Phase;

(c) the timetable for the work to be done by the Workgroup, in accordance with the timetable established pursuant to GR.19.1 (save where GR.19.5 applies); and

(d) the length of any Workgroup Consultation.

In addition, prior to the taking of any steps which would result in the undertaking of a significant amount of work (including the production of draft legal text to modify the Grid Code in order to give effect to a Grid Code Modification Proposal and/or Workgroup Alternative Grid Code Modification(s), with the relevant terms of reference setting out what a significant amount of work would be in any given case), the Workgroup shall seek the views of the Grid Code Review Panel as to whether to proceed with such steps and, in giving its views, the Grid Code Review Panel may consult the Authority in respect thereof.

GR.20.12 Subject to the provisions of this GR.20.12 and unless otherwise determined by the Grid Code Review Panel, the Workgroup shall develop and adopt its own internal working procedures for the conduct of its business and shall provide a copy of such procedures to the Panel Secretary in respect of each Grid Code Modification Proposal for which it is responsible. Unless the Grid Code Review Panel otherwise determines, meetings of each Workgroup shall be open to attendance by a representative of any User, (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice, the Citizens Advice Scotland, the Authority and any person invited by the chairperson, and the chairperson of a Workgroup may invite any such person to speak at such meetings, other than the Authority who may speak at any time as per GR.20.3.

GR.20.13 After development by the Workgroup of the Grid Code Modification Proposal, and (if applicable) after development of any draft Workgroup Alternative Grid Code Modification(s), the Workgroup may (subject to the provisions of GR.20.19) consult (“Workgroup Consultation”) on the Grid Code Modification Proposal and, if applicable, on any draft Workgroup Alternative Grid Code Modification(s) with:

(a) Users; and

(b) such other persons who may properly be considered to have an appropriate interest in it.

GR.20.14 The Workgroup Consultation will be undertaken by issuing a Workgroup Consultation paper (and its provision in electronic form on the Website and in electronic mails to Users and such other persons, who have supplied relevant details, shall meet this requirement).

Such Workgroup Consultation paper will include:

(a) Issues which arose in the Workgroup discussions;
(b) Details of any draft Workgroup Alternative Grid Code Modification(s);

(c) The date proposed by the Code Administrator as the Proposed Implementation Date.

GR.20.15 Workgroup Consultation papers will be copied to Core Industry Document Owners and the secretary of the STC committee.

GR.20.16 Any Authorised Electricity Operator; the Citizens Advice or the Citizens Advice Scotland, The Company or a Materially Affected Party may (subject to GR.20.20) raise a Workgroup Consultation Alternative Request in response to the Workgroup Consultation. Such Workgroup Consultation Alternative Request must include:

(a) the information required by GR.15.3 (which shall be read and construed so that any references therein to “amendment proposal” or “proposal” shall be read as “request” and any reference to “Proposer” shall be read as “requester”); and

(b) sufficient detail to enable consideration of the request including details as to how the request better facilitates the Grid Code Objectives than the current version of the Grid Code, than the Grid Code Modification Proposal and than any draft Workgroup Alternative Grid Code Modification(s).

GR.20.17 The Workgroup shall consider and analyse any comments made or any Workgroup Consultation Alternative Request made by any User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice and the Citizens Advice Scotland in response to the Workgroup Consultation.

GR.20.18 If a majority of the members of the Workgroup or the chairperson of the Workgroup believe that the Workgroup Consultation Alternative Request may better facilitate the Grid Code Objectives than the Grid Code Modification Proposal, the Workgroup shall develop it as a Workgroup Alternative Grid Code Modification(s) or, where the chairperson of the Workgroup agrees, amalgamate it with one or more other draft Workgroup Alternative Grid Code Modification(s) or Workgroup Consultation Alternative Request(s);

GR.20.19 Unless the Grid Code Review Panel directs the Workgroup otherwise pursuant to GR.20.20, and provided that a Workgroup Consultation has been undertaken in respect of the Grid Code Modification Proposal, no further Workgroup Consultation will be required in respect of any Workgroup Alternative Grid Code Modification(s) developed in respect of such Grid Code Modification Proposal.

GR.20.20 The Grid Code Review Panel may, at the request of the chairperson of the Workgroup, direct the Workgroup to undertake further Workgroup Consultation(s). At the same time as such direction the Grid Code Review Panel shall adjust the timetable referred to at GR.19.1(b) and the Code Administrator shall be entitled to adjust the timetable referred to at GR.19.1 (c), provided that the Authority, after receiving notice, does not object. No Workgroup Consultation Alternative Request may be raised by any User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice and the Citizens Advice Scotland during any second or subsequent Workgroup Consultation.

GR.20.21 The Workgroup shall finalise the Workgroup Alternative Grid Code Modification(s) for inclusion in the report to the Grid Code Review Panel.

(a) Each Workgroup chairperson shall prepare a report to the Grid Code Review Panel responding to the matters detailed in the terms of reference in accordance with the timetable set out in the terms of reference.

(b) If a Workgroup is unable to reach agreement on any such matter, the report must reflect the views of the members of the Workgroup.

(c) The report will be circulated in draft form to Workgroup members and a period of not less than five (5) Business Days or if all Workgroup members agree three...
(3) **Business Days** given for comments thereon. Any unresolved comments made shall be reflected in the final report.

**GR.20.23**

The chairperson or another member (nominated by the chairperson) of the **Workgroup** shall attend the next **Grid Code Review Panel** meeting following delivery of the report and may be invited to present the findings and/or answer the questions of **Panel Members** in respect thereof. Other members of the **Workgroup** may also attend such **Grid Code Review Panel** meeting.

**GR.20.24**

At the meeting referred to in GR.20.23 the **Grid Code Review Panel** shall consider the **Workgroup’s report** and shall determine whether to:-

(a) refer the proposed **Grid Code Modification Proposal** back to the **Workgroup** for further analysis (in which case the **Grid Code Review Panel** shall determine the timetable and terms of reference to apply in relation to such further analysis); or

(b) proceed then to wider consultation as set out in GR.21; or

(c) decide on another suitable course of action.

**GR.20.25**

Subject to GR.16.4 if, at any time during the assessment process carried out by the **Workgroup** pursuant to this GR.20, the **Workgroup** considers that a **Grid Code Modification Proposal** or any **Workgroup Alternative Grid Code Modification(s)** falls within the scope of a **Significant Code Review**, it shall consult on this as part of the **Workgroup Consultation** and include its reasoned assessment in the report to the **Grid Code Review Panel** prepared pursuant to GR.20.22. If the **Grid Code Review Panel** considers that the **Grid Code Modification Proposal** or the **Workgroup Alternative Grid Code Modification(s)** falls within the scope of a **Significant Code Review**, it shall consult with the **Authority**. If the **Authority** directs that the **Grid Code Modification Proposal** or **Workgroup Alternative Grid Code Modification(s)** falls within the scope of the **Significant Code Review**, the **Grid Code Modification Proposal** and any **Workgroup Alternative Grid Code Modification(s)** shall be suspended or withdrawn during the **Significant Code Review Phase**, in accordance with GR.16.3.

**GR.20.26**

The **Proposer** may, at any time prior to the final evaluation by the **Workgroup** (in accordance with its terms of reference and working practices) of that **Grid Code Modification Proposal** against the **Grid Code Objectives**, vary their **Grid Code Modification Proposal** on notice (which may be given verbally) to the chairperson of the **Workgroup** provided that such varied **Grid Code Modification Proposal** shall address the same issue or defect originally identified by the **Proposer** in their **Grid Code Modification Proposal**.

**GR.20.27**

The **Grid Code Review Panel** may (but shall not be obliged to) require a **Grid Code Modification Proposal** to be withdrawn if, in the Panel’s opinion, the **Proposer** of that **Grid Code Modification Proposal** is deliberately and persistently disrupting or frustrating the work of the **Workgroup** and that **Grid Code Modification Proposal** shall be deemed to have been so withdrawn. In the event that a **Grid Code Modification Proposal** is so withdrawn, the provisions of GR.15.10 shall apply in respect of that **Grid Code Modification Proposal**.

**GR.21**

**THE CODE ADMINISTRATOR CONSULTATION**

**GR.21.1**

In respect of any **Grid Code Modification Proposal** where a **Workgroup** has been established GR.21.2 to GR.21.6 shall apply.

**GR.21.2**

After consideration of any **Workgroup report** on the **Grid Code Modification Proposal** and if applicable any **Workgroup Alternative Grid Code Modification(s)** by the **Grid Code Review Panel** and a determination by the **Grid Code Review Panel** to proceed to wider consultation, the **Code Administrator** shall bring to the attention of and consult on the **Grid Code Modification Proposal** and if applicable any **Workgroup Alternative Grid Code Modification(s)** with:
(i) Users; and
(ii) such other persons who may properly be considered to have an appropriate interest in it, including Small Participants, the Citizens Advice and the Citizens Advice Scotland.

GR.21.3 The consultation will be undertaken by issuing a Consultation Paper (and its provision in electronic form on the Website and in electronic mails to Users and such other persons, who have supplied relevant details, shall meet this requirement). The consultation shall last for a minimum of one month unless it is deemed to be an Urgent Modification. For Urgent Modifications the Grid Code Review Panel shall confirm the proposed drafting for the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) do not include changes to Regulated Sections; provided there are no proposed changes to a Regulated Section then a shorter consultation duration can be applied if approved by the Authority, otherwise the standard one month consultation will apply.

GR.21.4 The Consultation Paper will contain:

(a) the proposed drafting for the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) (unless the Authority decides none is needed in the Grid Code Modification Report under GR.21.5) and will indicate the issues which arose in the Workgroup discussions, where there has been a Workgroup and will incorporate The Company’s and the Grid Code Review Panel’s initial views on the way forward; and

(b) the date proposed by the Code Administrator as the Proposed Implementation Date and, where the Workgroup terms of reference require and the dates proposed by the Workgroup are different from those proposed by the Code Administrator, those proposed by the Workgroup. In relation to a Grid Code Modification Proposal that meets the Self-Governance Criteria, the Code Administrator may not propose an implementation date earlier than the sixteenth (16) Business Day following the publication of the Grid Code Review Panel’s decision to approve or reject the Grid Code Modification Proposal. Views will be invited on these dates.

GR.21.5 Where the Grid Code Review Panel is of the view that the proposed text to amend the Grid Code for a Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) is not needed in the Grid Code Modification Report, the Grid Code Review Panel shall consult (giving its reasons as to why it is of this view) with the Authority as to whether the Authority would like the Grid Code Modification Report to include the proposed text to amend the Grid Code. If it does not, no text needs to be included. If it does, and no detailed text has yet been prepared, the Code Administrator shall prepare such text to modify the Grid Code in order to give effect to such Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) and shall seek the conclusions of the relevant Workgroup before consulting those identified in GR.21.2.

GR.21.6 Consultation Papers will be copied to Core Industry Document Owners and the secretary of the STC committee.

GR.21.7 In respect of any Grid Code Modification Proposal where a Workgroup has not been established GR.21.8 to GR.21.11 shall apply.

GR.21.8 After determination by the Grid Code Review Panel to proceed to wider consultation, such consultation shall be conducted by the Code Administrator on the Grid Code Modification Proposal with:

(i) Users; and
(ii) such other persons who may properly be considered to have an appropriate interest in it, including Small Participants, the Citizens Advice and the Citizens Advice Scotland.
GR.21.9 The consultation will be undertaken by issuing a Consultation Paper (and its provision in electronic form on the Website and in electronic mails to Users and such other persons, who have supplied relevant details, shall meet this requirement). The consultation shall last for a minimum of one month unless it is deemed to be an Urgent Modification. For Urgent Modifications the Grid Code Review Panel shall confirm the proposed drafting for the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) do not include changes to Regulated Sections; provided there are no proposed changes to a Regulated Section then a shorter consultation duration can be applied if approved by the Authority, otherwise the standard one month consultation will apply.

GR.21.10 The Consultation Paper will contain:

(a) the proposed drafting for the Grid Code Modification Proposal (unless the Authority decides none is needed in the Grid Code Modification Report under GR.21.11) and will incorporate The Company’s and the Grid Code Review Panel’s initial views on the way forward; and

(b) the date proposed by the Code Administrator as the Proposed Implementation Date. Views will be invited on this date.

GR.21.11 Where the Grid Code Review Panel is of the view that the proposed text to amend the Grid Code for a Grid Code Modification Proposal is not needed, the Grid Code Review Panel shall consult (giving its reasons to why it is of this view) with the Authority as to whether the Authority would like the Grid Code Modification Report to include the proposed text to amend the Grid Code. If it does not, no text needs to be included. If it does, and no detailed text has yet been prepared, the Code Administrator shall prepare such text to modify the Grid Code in order to give effect to such Grid Code Modification Proposal and consult those identified in GR.21.2.

GR.22 GRID CODE MODIFICATION REPORTS

GR.22.1 Subject to the Code Administrator’s consultation having been completed, the Grid Code Review Panel shall prepare and submit to the Authority a report (the "Grid Code Modification Report") in accordance with this GR.22 for each Grid Code Modification Proposal which is not withdrawn.

GR.22.1A Where a Grid Code Modification Proposal or any Workgroup Alternative Grid Code Modification constitutes an amendment to the Regulated Sections, the Panel will consider any consultation responses received and any further work required to assess these as required under GR.18.9.

GR.22.2 The matters to be included in a Grid Code Modification Report shall be the following (in respect of the Grid Code Modification Proposal):

(a) A description of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s), including the details of, and the rationale for, any variations made (or, as the case may be, omitted) by the Proposer together with the views of the Workgroup;

(b) the Panel Members’ Recommendation;

(c) a summary (agreed by the Grid Code Review Panel) of the views (including any recommendations) from Panel Members in the Grid Code Review Panel Recommendation Vote and the conclusions of the Workgroup (if there is one) in respect of the Grid Code Modification Proposal and of any Workgroup Alternative Grid Code Modification(s);

(d) an analysis of whether (and, if so, to what extent) the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) would better facilitate achievement of the Grid Code Objective(s) with a detailed explanation of the Grid Code Review Panel’s reasons for its assessment, including, where the
impact is likely to be material, an assessment of the quantifiable impact of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) on greenhouse gas emissions, to be conducted in accordance with such current guidance on the treatment of carbon costs and evaluation of the greenhouse gas emissions as may be issued by the Authority from time to time, and providing a detailed explanation of the Grid Code Review Panel’s reasons for that assessment;

(e) an analysis of whether (and, if so, to what extent) any Workgroup Alternative Grid Code Modification(s) would better facilitate achievement of the Grid Code Objective(s) as compared with the Grid Code Modification Proposal and any other Workgroup Alternative Grid Code Modification(s) and the current version of the Grid Code, with a detailed explanation of the Grid Code Review Panel’s reasons for its assessment, including, where the impact is likely to be material, an assessment of the quantifiable impact of the Workgroup Alternative Grid Code Modification(s) on greenhouse gas emissions, to be conducted in accordance with such current guidance on the treatment of carbon costs and evaluation of the greenhouse gas emissions as may be issued by the Authority from time to time, and providing a detailed explanation of the Grid Code Review Panel’s reasons for that assessment;

(f) the Proposed Implementation Date taking into account the views put forward during the process described at GR.21.4 (b) such date to be determined by the Grid Code Review Panel in the event of any disparity between such views and those of the Code Administrator;

(g) an assessment of:

   (i) the impact of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) on the Core Industry Documents and the STC;
   (ii) the changes which would be required to the Core Industry Documents and the STC in order to give effect to the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s);
   (iii) the mechanism and likely timescale for the making of the changes referred to in (ii);
   (iv) the changes and/or developments which would be required to central computer systems and, if practicable, processes used in connection with the operation of arrangements established under the Core Industry Documents and the STC;
   (v) the mechanism and likely timescale for the making of the changes referred to in (iv);
   (vi) an estimate of the costs associated with making and delivering the changes referred to in (ii) and (iv), such costs are expected to relate to: for (ii) the costs of amending the Core Industry Document(s) and STC and for (iv) the costs of changes to computer systems and possibly processes which are established for the operation of the Core Industry Documents and the STC, together with an analysis and a summary of representations in relation to such matters, including any made by Small Participants, the Citizens Advice and the Citizens Advice Scotland;

(h) to the extent such information is available to the Code Administrator, an assessment of the impact of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) on Users in general (or classes of Users in general), including the changes which are likely to be required to their internal systems and processes and an estimate of the development, capital and operating costs associated with implementing the changes to the Grid Code and to Core Industry Documents and the STC;

(i) copies of (and a summary of) all written representations or objections made by consultees during the consultation in respect of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) and subsequently maintained;
(j) a copy of any impact assessment prepared by Core Industry Document Owners and the STC committee and the views and comments of the Code Administrator in respect thereof;

(k) whether or not, in the opinion of The Company, the Grid Code Modification Proposal (or any Workgroup Alternative Grid Code Modification(s)) should be made.

(l) The Company's justification for including or not including the views resulting from the relevant consultation in the Grid Code Modification Report.

(m) where a Grid Code Modification Proposal or any Workgroup Alternative Grid Code Modification(s) constitutes an amendment to the areas set out in table 1 of the GR.B annex which details the Regulated Sections, the expected impact on the objectives of Retained EU Law (Commission Regulation (EU) 2017/2195).

GR.22.3 A draft of the Grid Code Modification Report will be circulated by the Code Administrator to Users, Panel Members and such other persons who may properly be considered to have an appropriate interest in it (and its provision in electronic form on the Website and in electronic mails to Users and Panel Members, who must supply relevant details, shall meet this requirement) and a period of no less than five (5) Business Days given for comments to be made thereon. Any unresolved comments made shall be reflected in the final Grid Code Modification Report.

GR.22.4 A draft of the Grid Code Modification Report shall be tabled at a meeting of the Grid Code Review Panel prior to submission of that Grid Code Modification Report to the Authority as set in accordance with the timetable established pursuant to GR.19.1, and at which the Panel may consider any minor changes to the legal drafting, which may include any issues identified through the Code Administrator consultation, and:

(i) if the change required is a typographical error the Grid Code Review Panel may instruct the Code Administrator to make the appropriate change and the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote; or

(ii) if the change required is not considered to be a typographical error then the Grid Code Review Panel may direct the Workgroup to review the change. If the Workgroup unanimously agree that the change is minor the Grid Code Review Panel may instruct the Code Administrator to make the appropriate change and the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote, otherwise for changes that are not considered to be minor the Code Administrator shall issue the Grid Code Modification Proposal for further Code Administrator consultation, after which the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote; or

(iii) in the case of a modification that had been directed pursuant to GR.19.2(e) to proceed directly to wider consultation without the formation of a Workgroup, and if the change required is not considered to be a typographical error, then the Grid Code Review Panel may direct the Code Administrator in conjunction with the Proposer to review the change. If the Grid Code Review Panel, the Code Administrator and the Proposer agree that the change is minor the Grid Code Review Panel may instruct the Code Administrator to make the appropriate change and the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote, otherwise for changes that are not considered to be minor the Code Administrator shall issue the Grid Code Modification Proposal for further Code Administrator consultation after which the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote. In the case of a change that is not considered to be minor, the Grid Code Review Panel may also consider whether to establish a Workgroup of the Grid Code Review Panel, to further consider the Grid Code Modification Proposal, in which case the procedures set out within GR.20 will
be followed as required; or

(iv) if a change is not required after consideration, the Panel Chairperson will undertake the Grid Code Review Panel Recommendation Vote.

GR.22.5 A draft of the Grid Code Modification Report following the Grid Code Review Panel Recommendation Vote will be circulated by the Code Administrator to Panel Members (and in electronic mails to Panel Members, who must supply relevant details, shall meet this requirement) and a period of no less than five (5) Business Days given for comments to be made on whether the Grid Code Modification Report accurately reflects the views of the Panel Members as expressed at the Grid Code Review Panel Recommendation Vote. Any unresolved comments made shall be reflected in the final Grid Code Modification Report.

GR.22.6 Each Grid Code Modification Report shall be addressed and furnished to the Authority and none of the facts, opinions or statements contained in such may be relied upon by any other person.

GR.22.7 Subject to GR.22.9 to GR.22.12, in accordance with the Transmission Licence, the Authority may approve the Grid Code Modification Proposal or a Workgroup Alternative Grid Code Modification(s) contained in the Grid Code Modification Report (which shall then be an "Approved Modification" until implemented).

GR.22.8 The Code Administrator shall copy (by electronic mail to those persons who have supplied relevant details to the Code Administrator) the Grid Code Modification Report to:

(i) each Panel Member; and
(ii) any person who may request a copy, and shall place a copy on the Website.

GR.22.9 Revised Fixed Proposed Implementation Date

GR.22.9.1 Where the Proposed Implementation Date included in a Grid Code Modification Report is a Fixed Proposed Implementation Date and the Authority considers that the Fixed Proposed Implementation Date is or may no longer be appropriate or might otherwise prevent the Authority from making such decision by reason of the effluxion of time the Authority may direct the Grid Code Review Panel to recommend a revised Proposed Implementation Date.

GR.22.9.2 Such direction may:

(a) specify that the revised Proposed Implementation Date shall not be prior to a specified date;

(b) specify a reasonable period (taking into account a reasonable period for consultation) within which the Grid Code Review Panel shall be requested to submit its recommendation; and

(c) provide such reasons as the Authority deems appropriate for such request (and in respect of those matters referred to in GR.22.9.2 (a) and (b) above).

GR.22.9.3 Before making a recommendation to the Authority, the Grid Code Review Panel will consult on the revised Proposed Implementation Date, and may in addition consult on any matters relating to the Grid Code Modification Report which in the Grid Code Review Panel's opinion have materially changed since the Grid Code Modification Report was submitted to the Authority and where it does so the Grid Code Review Panel shall report on such matters as part of its recommendation under Grid Code GR.22.9.4, with:

(a) Users; and

(b) such other persons who may properly be considered to have an appropriate interest in it. Such consultation will be undertaken in
GR.22.9.4 Following the completion of the consultation held pursuant to GR.22.9.3 the Grid Code Review Panel shall report to the Authority with copies of all the consultation responses and recommending a Revised Proposed Implementation Date.

GR.22.9.5 The Authority shall notify the Grid Code Review Panel as to whether or not it intends to accept the Revised Proposed Implementation Date and where the Authority notifies the Grid Code Review Panel that it intends to accept the Revised Proposed Implementation Date, the Revised Proposed Implementation Date shall be deemed to be the Proposed Implementation Date as specified in the Grid Code Modification Report.

GR.22.10 Authority Approval

If:

(a) the Authority has not given notice of its decision in respect of a Grid Code Modification Report within two (2) calendar months (in the case of an Urgent Modification), or four (4) calendar months (in the case of all other Grid Code Modification Proposals) from the date upon which the Grid Code Modification Report was submitted to it; or

(b) the Grid Code Review Panel is of the reasonable opinion that the circumstances relating to the Grid Code Modification Proposal and/or Workgroup Alternative Grid Code Modification which is the subject of a Grid Code Modification Report have materially changed, the Grid Code Review Panel may request the Panel Secretary to write to the Authority requesting the Authority to give an indication of the likely date by which the Authority's decision on the Grid Code Modification Proposal will be made.

GR.22.11 If the Authority determines that the Grid Code Modification Report is such that the Authority cannot properly form an opinion on the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s), or where the Grid Code Modification Proposal and/or any Workgroup Alternative Grid Code Modification(s) constitutes an amendment to the Regulated Sections of the code, where the Authority requires an amendment to the Grid Code Modification Proposal and/or any Workgroup Alternative Grid Code Modification(s) in order to approve it, it may issue a direction to the Grid Code Review Panel:

(a) specifying the additional steps (including drafting or amending existing drafting associated with the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s), revision (including revision to the timetable), analysis or information that it requires in order to form such an opinion; and

(b) requiring the Grid Code Modification Report to be revised and to be resubmitted.

GR.22.12 If a Grid Code Modification Report is to be revised and re-submitted in accordance with a direction issued pursuant to GR.22.11, it shall be re-submitted as soon after the Authority’s direction as is appropriate (and in the case of an amendment to the areas set out in table 1 of the GR.B annex which details the Regulated Sections of the code within 2 months), taking into account the complexity, importance and urgency of the Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s). The Grid Code Review Panel shall decide on the level of analysis and consultation required in order to comply with the Authority’s direction and shall agree an appropriate timetable for meeting its obligations. Once the Grid Code Modification Report is revised, the Grid Code Review Panel shall carry out its Grid Code Review Panel Recommendation Vote again in respect of the revised Grid Code Modification Report and re-submit it to the Authority in compliance with GR.22.4 to GR.22.6.

GR.23 URGENT MODIFICATIONS

GR.23.1 If a Relevant Party recommends to the Panel Secretary that a proposal should be
treated as an **Urgent Modification** in accordance with this GR.23, the Panel Secretary shall notify the Panel Chairperson who shall then, in accordance with GR.23.2 (a) to (e) inclusive, and notwithstanding anything in the contrary in these Governance Rules, endeavour to obtain the views of the Grid Code Review Panel as to the matters set out in GR.23.3. If for any reason the Panel Chairperson is unable to do that, the Panel Secretary shall attempt to do so (and the measures to be undertaken by the Panel Chairperson in the following paragraphs shall in such case be undertaken by the Panel Secretary).

**GR.23.2**

(a) The Panel Chairperson shall determine the time by which, in their opinion, a decision of the Grid Review Panel is required in relation to such matters, having regard to the degree of urgency in all circumstances, and references in this GR.23.1 to the “time available” shall mean the time available, based on any such determination by the Panel Chairperson;

(b) The Panel Secretary shall, at the request of the Panel Chairperson, convene a meeting or meetings (including meetings by telephone conference call, where appropriate) of the Grid Code Review Panel in such manner and upon such notice as the Panel Chairperson considers appropriate, and such that, where practicable within the time available, as many Panel Members as possible may attend;

(c) Each Panel Member shall be deemed to have consented, for the purposes of GR.8.9, to the convening of such meeting or meetings in the manner and on the notice determined by the Panel Chairperson. GR.8.10 shall not apply to any such business.

(d) Where:

   (i) it becomes apparent, in seeking to convene a meeting of the Grid Code Review Panel within the time available, that quorum will not be present; or

   (ii) it transpires that the meeting of the Grid Code Review Panel is not quorate and it is not possible to rearrange such meeting within the time available, the Panel Chairperson shall endeavour to contact each Panel Member individually in order to ascertain such Panel Member’s vote, and (subject to GR.23.2 (e)) any matter to be decided shall be decided by a majority of those Panel Members who so cast a vote. Where, for whatever reason no decision is reached, the Panel Chairperson shall proceed to consult with the Authority in accordance with GR.23.5;

(e) Where the Panel Chairperson is unable to contact at least four Panel Members within the time available and where:

   (i) It is only The Company, who has recommended that the proposal should be treated as an Urgent Modification, then those Panel Members contacted shall decide such matters, such decision may be a majority decision. Where in such cases no decision is made for whatever reason, the Panel Chairperson shall proceed to consult with the Authority in accordance with GR.23.5; or

   (ii) any User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice or the Citizens Advice Scotland has recommended that the proposal should be treated as an Urgent Modification, then the Panel Chairperson may decide the matter (in consultation with those Panel Members (if any) which they manage to contact) provided that the Panel Chairperson shall include details in the relevant Grid Code Modification Report of the steps which they took to contact other Panel Members first.

**GR.23.3**

The matters referred to in GR.23.1 are:

(a) whether such proposal should be treated as an Urgent Modification in accordance with this GR.23 and

(b) the procedure and timetable to be followed in respect of such Urgent Modification.
GR.23.4 The Panel Chairperson or, in their absence, the Panel Secretary shall forthwith provide the Authority with the recommendation (if any) ascertained in accordance with GR.23.2 (a) to (e) inclusive, of the Grid Code Review Panel as to the matters referred to in GR.23.2, and shall consult the Authority as to whether such Grid Code Modification Proposal is an Urgent Modification and, if so, as to the procedure and timetable which should apply in respect thereof.

GR.23.5 If the Grid Code Review Panel has been unable to make a recommendation in accordance with GR.23.2.(d) or GR.23.2.(e) as to the matters referred to in GR.23.3 then the Panel Chairperson or, in their absence, the Panel Secretary may recommend whether they consider that such proposal should be treated as an Urgent Modification and shall forthwith consult the Authority as to whether such Grid Code Modification Proposal is an Urgent Modification and, if so, as to the procedure and timetable that should apply in respect thereof.

GR.23.6 The Grid Code Review Panel shall:

(a) not treat any Grid Code Modification Proposal as an Urgent Modification except with the prior consent of the Authority;

(b) comply with the procedure and timetable in respect of any Urgent Modification approved by the Authority; and

(c) comply with any direction of the Authority issued in respect of any of the matters on which the Authority is consulted pursuant to GR.23.4 or GR.23.5.

GR.23.7 For the purposes of this GR.23.7, the procedure and timetable in respect of an Urgent Modification may (with the approval of the Authority pursuant to GR.23.4 or GR.23.5) deviate from all or part of the Grid Code Modification Procedures or follow any other procedure or timetable approved by the Authority except for the duration of the Code Administrator consultation for modifications relating to Regulated Sections which shall be for one month. Where the procedure and timetable approved by the Authority in respect of an Urgent Modification do not provide for the establishment (or designation) of a Workgroup the Proposer's right to vary the Grid Code Modification Proposal pursuant to GR.15.10 and GR.20.26 shall lapse from the time and date of such approval.

GR.23.8 The Grid Code Modification Report in respect of an Urgent Modification shall include:

(a) a statement as to why the Proposer believes that such Grid Code Modification Proposal should be treated as an Urgent Modification;

(b) any statement provided by the Authority as to why the Authority believes that such Grid Code Modification Proposal should be treated as an Urgent Modification;

(c) any recommendation of the Grid Code Review Panel (or any recommendation of the Panel Chairperson) provided in accordance with GR.23 in respect of whether any Grid Code Modification Proposal should be treated as an Urgent Modification; and

(d) the extent to which the procedure followed deviated from the process for Standard Modifications (other than the procedures in this GR.23).

GR.23.9 Each Panel Member shall take all reasonable steps to ensure that an Urgent Modification is considered, evaluated and (subject to the approval of the Authority) implemented as soon as reasonably practicable, having regard to the urgency of the matter and, for the avoidance of doubt, an Urgent Modification may (subject to the approval of the Authority) result in the Grid Code being amended on the day on which such proposal is submitted.

GR.23.10 Where an Urgent Modification results in an amendment being made in accordance with GR.25, the Grid Code Review Panel may or (where it appears to the Grid Code Review
Panel that there is a reasonable level of support for a review amongst Users) shall following such amendment, establish a Workgroup on terms specified by the Grid Code Review Panel to consider and report as to whether any alternative amendment could, as compared with such amendment better facilitate achieving the Grid Code Objectives in respect of the subject matter of that Urgent Modification.

GR.24 SELF-GOVERNANCE

GR.24.1 If the Grid Code Review Panel, having evaluated a Grid Code Modification Proposal against the Self-Governance Criteria, pursuant to GR.18.4, considers that the Grid Code Modification Proposal meets the Self-Governance Criteria, the Grid Code Review Panel shall submit to the Authority a Self-Governance Statement setting out its reasoning in reasonable detail.

GR.24.2 The Authority may, at any time prior to the Grid Code Review Panel’s determination made pursuant to GR.24.9, give written notice that it disagrees with the Self-Governance Statement and may direct that the Grid Code Modification Proposal proceeds through the process for Standard Modifications set out in GR.19, GR.20, GR.21 and GR.22.

GR.24.3 Subject to GR.24.2, after submitting a Self-Governance Statement, the Grid Code Review Panel shall follow the procedure set out in GR.19, GR.20, GR.21 and GR.22.

GR.24.4 The Authority may issue a direction to the Grid Code Review Panel in relation to a Modification to follow the procedure set out for Modifications that meet the Self-Governance Criteria, notwithstanding that no Self-Governance Statement has been submitted or a Self-Governance Statement has been retracted.

GR.24.5 Subject to the Code Administrator’s consultation having been completed pursuant to GR.21, the Grid Code Review Panel shall prepare a report (the “Grid Code Modification Self-Governance Report”).

GR.24.6 The matters to be included in a Grid Code Modification Self-Governance Report shall be the following (in respect of the Grid Code Modification Proposal):

(a) details of its analysis of the Grid Code Modification Proposal against the Self-Governance Criteria;

(b) copies of all consultation responses received;

(c) the date on which the Grid Code Review Panel Self-Governance Vote shall take place, which shall not be earlier than seven (7) days from the date on which the Grid Code Modification Self-Governance Report is furnished to the Authority in accordance with GR.24.8; and

(d) such other information that is considered relevant by the Grid Code Review Panel.

GR.24.7 A draft of the Grid Code Modification Self-Governance Report will be circulated by the Code Administrator to Users and Panel Members (and its provision in electronic form on the Website and in electronic mails to Users and Panel Members, who must supply relevant details, shall meet this requirement) and a period of no less than five (5) Business Days given for comments to be made thereon. Any unresolved comments made shall be reflected in the final Grid Code Modification Self-Governance Report.

GR.24.8 Each Grid Code Modification Self-Governance Report shall be addressed and furnished to the Authority and none of the facts, opinions or statements contained in such Grid Code Modification Self-Governance Report may be relied upon by any other person.

GR.24.9 Subject to GR.24.11, if the Authority does not give written notice that its decision is required pursuant to GR.24.2, or if the Authority determines that the Self-Governance Criteria are satisfied in accordance with GR.24.4, then the Grid Code Modification Self-Governance Report shall be tabled at the Panel Meeting following
submission of that Grid Code Modification Self-Governance Report to the Authority at which the Panel Chairperson will undertake the Grid Code Review Panel Self-Governance Vote and the Code Administrator shall give notice of the outcome of such vote to the Authority as soon as possible thereafter.

GR.24.10 If the Grid Code Review Panel vote to approve the Grid Code Modification Proposal pursuant to GR.24.9 (which shall then be an “Approved Grid Code Self-Governance Proposal”) until implemented).


GR.24.12 The Code Administrator shall make available on the Website and copy (by electronic mail to those persons who have supplied relevant details to the Code Administrator) the Grid Code Modification Self-Governance Report prepared in accordance with GR.24 to:

(i) each Panel Member; and
(ii) any person who may request a copy, and shall place a copy on the Website.

GR.24.13 A User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice or the Citizens Advice Scotland may appeal to the Authority the approval or rejection by the Grid Code Review Panel of a Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) in accordance with GR.24.9, provided that the Panel Secretary is also notified, and the appeal has been made up to and including fifteen (15) Business Days after the Grid Code Review Panel Self-Governance Vote has been undertaken pursuant to GR.24.9. If such an appeal is made, implementation of the Grid Code Modification Proposal shall be suspended pending the outcome. The appealing User (including any Authorised Electricity Operator; The Company or a Materially Affected Party), the Citizens Advice or the Citizens Advice Scotland must notify the Panel Secretary of the appeal when the appeal is made.

GR.24.14 The Authority shall consider whether the appeal satisfies the following criteria:

(a) The appealing party is, or is likely to be, unfairly prejudiced by the implementation or non-implementation of that Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s); or

(b) The appeal is on the grounds that, in the case of implementation, the Grid Code Modification Proposal or Workgroup Alternative; or

(c) Grid Code Modification(s) may not better facilitate the achievement of at least one of the Grid Code Objectives; or

(d) The appeal is on the grounds that, in the case of non-implementation, the Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) may better facilitate the achievement of at least one of the Grid Code Objectives; and

(e) It is not brought for reasons that are trivial, vexatious or have no reasonable prospect of success and if the Authority considers that the criteria are not satisfied, it shall dismiss the appeal.

GR.24.15 Following any appeal to the Authority, a Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) shall be treated in accordance with any decision and/or direction of the Authority following that appeal.
GR.24.16 If the Authority quashes the Grid Code Review Panel’s determination in respect of a Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) made in accordance with GR.24.9 and takes the decision on the relevant Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) itself, following an appeal to the Authority, the Grid Code Review Panel’s determination of that Grid Code Modification Proposal and any Workgroup Alternative Grid Code Modification(s) contained in the relevant Grid Code Modification Self Governance Report shall be treated as a Grid Code Modification Report submitted to the Authority pursuant to GR.22.6 (for the avoidance of doubt, subject to GR.22.8 to GR.22.12) and the Grid Code Review Panel’s determination shall be treated as its recommendation pursuant to GR.22.4.

GR.24.17 If the Authority quashes the Grid Code Review Panel’s determination in respect of a Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) made in accordance with GR.24.9, the Authority may, following an appeal to the Authority, refer the Grid Code Modification Proposal back to the Grid Code Review Panel for further re-consideration and a further Grid Code Review Panel Self-Governance Vote.

GR.24.18 Following an appeal to the Authority, the Authority may confirm the Grid Code Review Panel’s determination in respect of a Grid Code Modification Proposal or Workgroup Alternative Grid Code Modification(s) made in accordance with GR.24.9.

GR.25 IMPLEMENTATION

GR.25.1 The Grid Code shall be modified either in accordance with the terms of the direction by the Authority relating to, or other approval by the Authority of, the Grid Code Modification Proposal or any Workgroup Alternative Grid Code Modification(s) contained in the relevant Grid Code Modification Report, or in respect of Grid Code Modification Proposals or any Workgroup Alternative Grid Code Modification(s) that are subject to the determination of the Grid Code Review Panel pursuant to GR.24.9, in accordance with the relevant Grid Code Modification Self-Governance Report subject to the appeal procedures set out in GR.24.13 to GR.24.18.

GR.25.2 The Code Administrator shall forthwith notify (by publication on the Website and, where relevant details are supplied by electronic mail):

(a) each User;
(b) each Panel Member;
(c) the Authority;
(d) each Core Industry Document Owner;
(e) the secretary of the STC committee;
(f) each Materially Affected Party; and
(g) the Citizens Advice and the Citizens Advice Scotland of the change so made and the effective date of the change.

GR.25.3 A modification of the Grid Code shall take effect from the time and date specified in the direction, or other approval, from the Authority referred to in GR.25.1 or, in the absence of any such time and date in the direction or approval, from 00:00 hours on the day falling ten (10) Business Days after the date of such direction, or other approval, from the Authority. A modification of the Grid Code pursuant to GR.24.9 shall take effect, subject to the appeal procedures set out in GR.24.1313 to GR.24.18, from the time and date specified by the Code Administrator in its notice given pursuant to GR.25.2, which shall be given after the expiry of the fifteen (15) Business Day period set out in GR.24.13 to allow for appeals, or where an appeal is raised in accordance with GR.24.13, on conclusion of the appeal in accordance with GR.24.15 or GR.24.18 but where conclusion of the appeal is earlier than the fifteen (15) Business Day period set out in GR.24.13, notice shall be given after the expiry of this period. A modification of the Grid Code pursuant to GR.26 shall take effect from the date specified in the Grid Code Modification Fast Track Report.
GR.25.4 A modification made pursuant to and in accordance with GR.25.1 shall not be impaired or invalidated in any way by any inadvertent failure to comply with or give effect to this Section.

GR.25.5 If a modification is made to the Grid Code in accordance with the Transmission Licence but other than pursuant to the other Grid Code Modification Procedures in these Governance Rules, the Grid Code Review Panel shall determine whether or not to submit the modification for review by a Workgroup established on terms specified by the Grid Code Review Panel to consider and report as to whether any alternative modification could, as compared with such modification better facilitate achieving the Grid Code Objectives in respect of the subject matter of the original modification. Where such a Workgroup is established the provisions of GR.20 shall apply as if such a modification were a Grid Code Modification Proposal.

Transitional Issues

GR.25.6 Notwithstanding the provisions of GR.25.3, Modification GC0132 changes the Grid Code process for Grid Code Modification Proposals and therefore may affect other Grid Code Modification Proposals which have not yet become Approved Modifications. Consequently, this GR.25.6 deals with issues arising out of the implementation of Modification GC0132. In particular this deals with which version of the Grid Code process for Grid Code Modification Proposals will apply to Grid Code Modification Proposal(s) which were already instigated prior to the implementation of Modification GC0132.

Any Grid Code Modification Proposal in respect of which a Grid Code Modification Report has been sent to the Authority prior to the date and time of implementation of Modification GC0132 is known as an “Old Modification”. Any Grid Code Modification Proposal in respect of which a Grid Code Modification Report has not been sent to the Authority as at the date and time of implementation of Modification GC0132 is known as a “New Modification”. The Grid Code provisions which will apply to any Old Modification(s) are the provisions of the Grid Code in force immediately prior to the implementation of GC0132. The provisions of the Grid Code which will apply to any New Modifications are the provisions of the Grid Code in force and as amended from time to time.

GR.25.7 Notwithstanding the provisions of GR.25.3, Modification GC0131 changes the Grid Code process for Grid Code Modification Proposals and therefore may affect other Grid Code Modification Proposals which have not yet become Approved Modifications. Consequently, this GR.25.7 deals with issues arising out of the implementation of Modification GC0131. In particular this deals with which version of the Grid Code process for Grid Code Modification Proposals will apply to Grid Code Modification Proposal(s) which were already instigated prior to the implementation of Modification GC0131.

Any Grid Code Modification Proposal in respect of which a Grid Code Modification Report has been sent to the Authority prior to the date and time of implementation of Modification GC0131 is known as an “Old GC0131 Modification”. Any Grid Code Modification Proposal in respect of which a Grid Code Modification Report has not been sent to the Authority as at the date and time of implementation of Modification GC0131 is known as a “New GC0131 Modification”. The Grid Code provisions which will apply to any Old GC0131 Modification(s) are the provisions of the Grid Code in force immediately prior to the implementation of GC0131. The provisions of the Grid Code which will apply to any New GC0131 Modifications are the provisions of the Grid Code in force from time to time.

GR.26 FAST TRACK

GR.26.1 Where a Proposer believes that a modification to the Grid Code which meets the Fast Track Criteria is required, a Grid Code Fast Track Proposal may be raised. In such case the Proposer is only required to provide the details listed in GR.15.3 (a), (b), (c), (d), (e) and (k).
Provided that the **Panel Secretary** receives any modification to the **Grid Code** which the **Proposer** considers to be a **Grid Code Fast Track Proposal**, not less than ten (10) **Business Days** (or such shorter period as the **Panel Secretary** may agree, provided that the **Panel Secretary** shall not agree any period shorter than five (5) **Business Days**) prior to the next **Grid Code Review Panel** meeting, the **Panel Secretary** shall place the **Grid Code Fast Track Proposal** on the agenda of the next **Grid Code Review Panel** meeting, and otherwise, shall place it on the agenda of the next succeeding **Grid Code Review Panel** meeting.

To facilitate the discussion at the **Grid Code Review Panel** meeting, the **Code Administrator** will circulate a draft of the **Grid Code Modification Fast Track Report** to **Users**, the **Authority** and **Panel Members** (and its provision in electronic form on the **Website** and in electronic mails to **Users**, the **Authority** and **Panel Members**, who must supply relevant details, shall meet this requirement) for comment not less than five (5) **Business Days** ahead of the **Grid Code Review Panel** meeting which will consider whether or not the **Fast Track Criteria** are met and whether or not to approve the **Grid Code Fast Track Proposal**.

It is for the **Grid Code Review Panel** to decide whether or not a **Grid Code Fast Track Proposal** meets the **Fast Track Criteria** and if it does, to determine whether or not to approve the **Grid Code Fast Track Proposal**.

The **Grid Code Review Panel's** decision that a **Grid Code Fast Track Proposal** meets the **Fast Track Criteria** pursuant to GR.26.4 must be unanimous.

The **Grid Code Review Panel's** decision to approve the **Grid Code Fast Track Proposal** pursuant to GR.26.4 must be unanimous.

If the **Grid Code Review Panel** vote unanimously that the **Grid Code Fast Track Proposal** meets the **Fast Track Criteria** and to approve the **Grid Code Fast Track Proposal** (which shall then be an “**Approved Fast Track Proposal**”) until implemented, or until an objection is received pursuant to GR.26.12, then subject to the objection procedures set out in GR.26.12 the **Grid Code Fast Track Proposal** will be implemented by **The Company** without the **Authority**'s approval. **The Company** shall, in accordance with GR.15.4(a) notify the **Proposer** that additional information is required if the **Proposer** wishes the **Grid Code Modification Proposal** to continue.

Provided that the **Grid Code Review Panel** have unanimously agreed to treat a **Grid Code Modification Proposal** as a **Grid Code Fast Track Proposal** and unanimously approved that **Grid Code Fast Track Proposal**, the **Grid Code Review Panel** shall prepare and approve the **Grid Code Modification Fast Track Report** for issue in accordance with GR.26.11.

The matters to be included in a **Grid Code Modification Fast Track Report** shall be the following (in respect of the **Grid Code Fast Track Proposal**):

(a) a description of the proposed modification and of its nature and purpose;

(b) details of the changes required to the Grid Code, including the proposed legal text to modify the Grid Code to implement the **Grid Code Fast Track Proposal**;

(c) details of the votes required pursuant to GR.26.5 and GR.26.6;

(d) the intended implementation date, from which the **Approved Fast Track Proposal** will take effect, which shall be no sooner than fifteen (15) **Business Days** after the date of notification of the **Grid Code Review Panel's** decision to approve; and

(e) details of how to object to the **Approved Fast Track Proposal** being made
Upon approval by the Grid Code Review Panel of the Grid Code Modification Fast Track Report, the Code Administrator will issue the report in accordance with GR.26.11.

The Code Administrator shall copy (by electronic mail to those persons who have supplied relevant details to the Code Administrator) the Grid Code Modification Fast Track Report prepared in accordance with GR.26 to:

(i) each Panel Member;
(ii) the Authority; and
(iii) any person who may request a copy, and shall place a copy on the Website.

A User, any Authorised Electricity Operator; The Company or a Materially Affected Party, the Citizens Advice, the Citizens Advice Scotland or the Authority may object to the Approved Fast Track Proposal being implemented, and shall include with such objection the reasons for the objection. Any such objection must be made in writing (including by email) and be clearly stated to be an objection to the Approved Fast Track Proposal in accordance with this GR.26 of the Grid Code and be notified to the Panel Secretary by the date up to and including fifteen (15) Business Days after notification of the Grid Code Review Panel’s decision to approve the Grid Code Fast Track Proposal. If such an objection is made the Approved Fast Track Proposal shall not be implemented. The Panel Secretary will notify each Panel Member and the Authority of the objection. The Panel Secretary shall notify the Proposer, in accordance with GR.15.4A that additional information is required if the Proposer wishes the Grid Code Modification Proposal to continue.
ANNEX GR.A - ELECTION OF USERS' PANEL MEMBERS

Grid Code Review Panel Election Process

1. The election process has two main elements: nomination and selection.
2. The process will be used to appoint Panel Members in the category of Supplier, Generator, Offshore Transmission Owner and Onshore Transmission Owner.
3. The Code Administrator will publish the Election timetable by [September] in the year preceding the start of each term of office of Panel Members.
4. Each step of the process set out below will be carried out in line with the published timetable.
5. The Code Administrator will establish an Electoral Roll from representatives of parties listed on CUSC Schedule 1 or designated by the Authority as a Materially Affected Party as at 31st August in the year preceding the start of each term of office of Panel Members.
6. The Code Administrator will keep the Electoral Roll up to date.

Nomination Process

7. Each party on the Electoral Roll may nominate a candidate to stand for election for the Grid Code Review Panel.
8. Parties may only nominate a candidate for their own category; a Supplier may nominate a candidate for the Supplier Panel Member seat and a Generator may nominate a candidate for the Generator Panel Member seats. If a party able to nominate a candidate is both a Supplier and a Generator, they may nominate a candidate in each category.
9. The nominating party must complete the nomination form which will be made available by the Code Administrator and return it to the Code Administrator by the stated deadline.
10. The Code Administrator will draw up a list of candidates for each category of election.
11. Where there are fewer candidates than seats available or the same number of candidates as seats available, no election will be required and the nominated candidate(s) will be elected. The Code Administrator will publish a list of the successful candidates on the Grid Code website and circulate the results by email to the Grid Code circulation list.

Selection Process

12. The Code Administrator will send a numbered voting paper to each party on the electoral roll for each of the elections in which they are eligible to vote. The voting paper will contain a list of candidates for each election and will be sent by email.
14. Panel Members will be elected using the First Past the Post method.
15. In the event of two or more candidates receiving the same number of votes, the Code Administrator will draw lots to decide who is elected.
16. The Code Administrator will publish the results of the election on the Grid Code website and circulate the results by email to the Grid Code circulation list.
17. The Code Administrator will send an Election Report to Ofgem after the election is complete.
ANNEX GR.B Regulated Sections

The Grid Code sections identified in Tables 1 and 2 are considered to be Regulated Sections.

### Table 1 - Mapping of Electricity Balancing Regulation Article 18 Terms and Conditions for Balancing Service Providers and Balancing Responsible Parties to the Grid Code

<table>
<thead>
<tr>
<th>Commission Regulation (EU) 2017/2195 Reference (Retained EU Law)</th>
<th>Description</th>
<th>Grid Code Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>18.2</td>
<td>The terms and conditions pursuant to paragraph 1 shall also include the rules for suspension and restoration of market activities pursuant to Article 36 of Regulation (EU) 2017/2196 and rules for settlement in case of market suspension pursuant to Article 39 of Regulation (EU) 2017/2196 once approved in accordance with Article 4 of Regulation (EU) 2017/2196.</td>
<td>OC9.4</td>
</tr>
<tr>
<td>18.4.a</td>
<td>define reasonable and justified requirements for the provisions of balancing services;</td>
<td>BC1, BC2, BC3 &amp; BC4</td>
</tr>
<tr>
<td>18.4.b</td>
<td>allow the aggregation of demand facilities, energy storage facilities and power generating facilities in a scheduling area to offer balancing services subject to conditions referred to in paragraph 5 (c);</td>
<td>DRSC 4.2, BC1.4</td>
</tr>
<tr>
<td>18.5.a</td>
<td>the rules for the qualification process to become a balancing service provider pursuant to Article 16;</td>
<td>BC5, BC4.4.2</td>
</tr>
<tr>
<td>18.5.c</td>
<td>the rules and conditions for the aggregation of demand facilities, energy storage facilities and power generating facilities in a scheduling area to become a balancing service provider;</td>
<td>BC1.4 and BC1.A.10</td>
</tr>
<tr>
<td>18.5.d</td>
<td>the requirements on data and information to be delivered to the connecting TSO and, where relevant, to the reserve connecting DSO during the prequalification process and operation of the balancing market;</td>
<td>DRC, BC5 BC1.4,</td>
</tr>
<tr>
<td>18.5. f</td>
<td>the requirements on data and information to be delivered to the connecting TSO and, where relevant, to the reserve connecting DSO to evaluate the provisions of balancing services pursuant to Article 154(1), Article 154(8), Article 158(1)(e), Article 158(4)(b), Article 161(1)(f) and Article 161(4)(b) of Regulation (EU) 2017/1485;</td>
<td>BC1.4, BC1.A.10,</td>
</tr>
<tr>
<td>18.5. g</td>
<td>the definition of a location for each standard product and each specific product taking into account paragraph 5 (c);</td>
<td>BC1.4</td>
</tr>
</tbody>
</table>
the requirements on data and information to be delivered to the connecting TSO to calculate the imbalances;

BC1.4.2.3.4, BC1 Appendix 1 BC2.5.1,

the rules for balance responsible parties to change their schedules prior to and after the intraday energy gate closure time pursuant to paragraphs 3 and 4 of Article 17;

BC1.4.3.4,

Table 2 - Mapping of Network Code on Emergency and Restoration (NCER) Article 4(4) Terms and Conditions for System Defence and System Restoration Service Providers to the Grid Code

<table>
<thead>
<tr>
<th>Commission Regulation (EU) 2017/2196 Reference (Retained EU Law)</th>
<th>Description</th>
<th>Grid Code Reference</th>
</tr>
</thead>
</table>
| 4(4)(a) | The terms and conditions to act as defence service provider and as restoration service provider shall be established either in the national legal framework or on a contractual basis. If established on a contractual basis, each TSO shall develop by 18 December 2018 a proposal for the relevant terms and conditions, which shall define at least: (a) the characteristics of the service to be provided | **Restoration services:**  
- Re-energisation procedure: OC.9.2.5, OC.9.4.7  
- Re-synchronisation procedure: OC9.4.7, BC2.9.2.2(iii))  
- Frequency deviation management: BC3.4, BC.3.5, BC3.6, BC3.7 BC2.5.4  

**Defence services:**  
- Frequency deviation management: BC3.4, BC.3.5, BC3.6, BC3.7 BC2.5.4, Fast Start: CC/ECC.6.3.14  
- Limited Frequency Sensitive Mode: ECC.6.3.7.1, ECC.6.3.7.2, BC3.7.2  
- Low Frequency Demand disconnection: CC/ECC.6.4.3, CC/ECC.A.5, OC6.5, OC6.6  
- Over Frequency control: ECC.6.3.7.1, ECC.6.3.7.3, BC.3.7.1, BC.3.7.2  
- Frequency deviation management: BC3.4, BC.3.5, BC3.6, BC3.7, CC/ECC.6.3.3, CC.6.3.7(a), ECC.6.3.7.3, CC.6.3.6(a)/ ECC.6.3.6, CC/ECC.6.3.9, DRSC 5.1, DRSC 6.1, DRSC 7.1, BC1.4.2, BC1. A.1.1, BC2.6.1, BC2.7, BC2.9, OC7.4.5, OC6.7, OC6.5, OC.10, Voltage deviation management: CC/ECC.6.1.4, CC/ECC.6.3.2, CC.6.3.6(b), ECC.6.3.6.3, ECC.6.4.5, BC2.8, BC2. A.2, DRSC.5, Power flow management: CC.6.3.7(a), ECC.6.3.7.3, CC/ECC.6.3.9, BC.1.4.2, BC1.5.5, BC1.1.1, BC.2.6.1, BC2.7, BC2.9, OC7.4.5, OC6.7, OC10, OC6.5, DRSC 5.1, Assistance for active power: BC2.7, BC2.9, OC9.4, CC9.5, OC.7.4.8, Manual Demand disconnection: OC.6.5, OC6.7, BC2.9 |
| 4(4) | (b) the possibility of and conditions for aggregation; and | DRSC1, DRSC2, DRSC4 ECC/CC 6.5 BC1.4 BC1. A.10 BC |

*END OF GOVERNANCE RULES*
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, which was revised 47 times. Issue 6 was published to incorporate all the non-material amendments as a result of modification GC0136.

R.4 This Revisions section provides a summary of the sections of the Grid Code changed by each revision to Issue 6.

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
<table>
<thead>
<tr>
<th>Revision</th>
<th>Section</th>
<th>Related Modification</th>
<th>Effective Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
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