Draft Grid Code

2021

INTRODUCTION

Pursuant to Section 35 of NEPRA Act (referred to as 'the Act' hereafter) and Section 23G of The Act prescribes the responsibilities of System Operator, among other duties, to ensure that there is in force at all times a Grid Code updating for the needs of its functions stated in Section 23H. It states "A system operator shall, from time to time and subject to approval by the Authority, make such grid management code as maybe required to enable it to carry out its functions as a system operator".

Consequently, NTDC, in its capacity as a System Operator, is required to submit a comprehensive Grid Code for approval of the Authority in accordance with the requirement of Section 23G and 23H of the Act. The Grid Code provides for the smooth and effective functioning of SO, Generators, BPCs, and other NEPRA licensees that are or will be connected to the Transmission System.

The Grid Code is an essential requirement of the regulation of electric network supply and delivery system. In accordance with the Act, all existing and future Users of the electric network supply and delivery system need a relevant Licence from NEPRA; and register as Code Participants with SO as per the provisions of Grid Code. One of the SO Licence's requirements is that Users of the Transmission System must comply with the provisions of Grid Code at all times. Failure to do so may result in their licence being suspended or revoked or disconnection from Transmission System.

The Grid Code sets out the guidelines, rules and procedures to be adopted by all Code Participants. The sub-codes of the Grid Code relate to technical relationships between SO and Code Participants.

The purpose of Grid Code is to provide unambiguous guidelines, rules and procedures, which ensure that all Users of Grid Code understand and abide by the obligations and responsibilities placed upon them under this Grid Code. The Code covers day-to-day and long-term principles, standards, procedures and guidelines for planning, operation, dispatch, and connection purposes for normal and abnormal Transmission System conditions.

The Grid Code sets out the operating procedures and principles between the SO; and all authorised Electricity Operators as defined in NTDC transmission licence collectively referred to as "Users" in the context of this document.

The Grid Code is structured so as to ensure that the National Grid can be developed, operated, and maintained in an efficient, safe, reliable and co-ordinated manner.

It seeks to avoid any undue discrimination between various Users themselves; between the entities within a particular User group type; and in day-to-day working relationship of SO with Users.

In implementing and complying with the Grid Code, neither the TNO(s) nor the System Operator shall unduly discriminate in any manner between any purchasers, procurers, providers or recipients of electric power, or providers of ancillary services.

The Main Objectives of the Grid Code are:

(a) To facilitate the planning, development, operation, and maintenance of an efficient, co-ordinated, safe, reliable and economical system for the transmission of electric power;

(b) To facilitate competition in the provision of electric power;

(c) To cover all material technical aspects including the operation of electric lines and electric plants connected to the Transmission System in so far as relevant to the Operation and Use of

Transmission System; and

(d) To achieve the Performance Standards (Transmission) Rules specified under the Act;

This Grid Code includes the following sub-codes:

(a) **Code Management**

Code Management, which sets out general terms and conditions and procedures to be adopted by all parties in the process of administering, updating, and amending of the Grid Code.

(b) **Planning Code**

The Planning Code, which deals with principles, standards, processes, and procedures along with data supply of information exchange by Users requirements between parties in order to undertake planning and development to ensure an efficient, economic, safe, reliable, and secure economic, and timely development of the Transmission System to meet the forecasted Total System Demand and margin of Operating Reserve requirements.

(c) **Connection Code**

The Connection Code, which sets out the minimum technical, design and operational criteria to be complied with by Users connected to or seeking connection with the Transmission System.

(d) **Operation Code**

The Operation Code, which sets out the principles, criteria, standards, procedures, and guidelines to be followed by SO and Users to ensure safe, adequate, secure and an efficient operation of the Transmission System, for real-time, and for managing short-term planning of system operations, and dealing with normal and abnormal circumstances during system operation.

(e) **Scheduling and Dispatch Code**

The Scheduling and Dispatch Code, which sets out principles, processes and procedures to ensure Security Constrained Economic Dispatch (SCED), the relationship between SO and Generators, including the dispatch and balancing process; and requirements for ancillary services and provisions for frequency control. It also places an obligation upon Users to supply certain data information to the SO in a timely manner.

(f) **Protection and Control Code**

The Protection and Control Code places the protection requirements upon the Users in terms of principles, standards, design, and procedures to ensure safe, reliable, secure and effective functioning of the Transmission System.

(g) **Metering Code**

The Metering Code places the Metering requirements upon the Users in terms of principles, standards, design, and procedures to ensure accurate, reliable, secure metering among the Users of Transmission System.

(h) **Data Registration Code**

The Data Registration Code, which sets out a unified listing of all data required by SO from Users; and by Users from SO, from time to time under the Grid Code.

(i) **Definitions**

The Definitions, which provides explanation of the special terms used in this Grid Code.

The Grid Code specifies all the material, technical design, and operational aspects of the interface requirements among Users.

The Distribution Code shall be consistent in material particulars with the Grid Code; and it shall ensure strict compliance by the Distribution Companies (DISCOs), Distribution Network Operators (DNO) and other Users with the provisions of Grid Code including, without limitation, the instructions from time to time of TNO and/or the SO in respect of the Use and Operation of their systems.

The institution of the Competitive Trading Bilateral Contracts Market (CTBCM) will be governed by Commercial Code that will set out the commercial relationships and interactions among Pakistan's Power Market stakeholders. Thus the Grid Code and Commercial Code with support and complement each other in system operation and market operation.

Finally, via Interconnectors Technical Codes and contractual Agreements between interconnected parties, the Grid Codes of Pakistan and other jurisdictions shall interact, in order to effectively deal with possible system limitations of different stakeholders and manage safe and secure operation of interconnectors without putting any external parties to undue risks.

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Grid Code

CODE MANAGEMENT

CM 1 **INTRODUCTION**

This Code Management (CM) contains provisions which are of general application to all sub-codes of the Grid Code. Their purpose is to ensure, as much as possible, that various sub-codes work collectively and in harmony for the benefit of all Code Participants of the Transmission System.

CM 2 **OBJECTIVE**

The principal objectives of the CM are the following:

(a) Specify the legal and regulatory framework for implementing and enforcing the Grid Code;

(b) Specify the purpose, functions, and composition of the Grid Code Review Panel (GCRP);

(c) Set a structured procedure for seeking and approving any Amendments to the Grid Code or Derogations from one or more of Code's provisions;

(d) Specify the rules to deal with any unforeseen or unexpected event on the Transmission System or related to the Grid Code; and

(e) Specify the general rules for interpreting the provisions of the Grid Code.

CM 3 **SCOPE**

The CM applies to the Code Participants which shall include, but shall not be limited to, the following:

(a) System Operator (SO);

(b) Transmission Network Operators (NGC, PGCs, RGCs, SPTLs, DISCOs, etc.);

(c) Transmission-connected Generators;

(d) Transmission-connected Consumers;

(e) Interconnectors (AC or DC);

(f) Energy Storage Units;

(g) Demand Side Units (DISCOs, Suppliers, BPCs);

(h) Meter Service Provider (MSP);

(i) Distribution Network Operators (DNOs);

(j) Market Operator (MO); and

(k) Small/Embedded Generators whether represented through an Aggregators or any other arrangement approved by NEPRA.

CM 4 **IMPLEMENTATION AND ENFORCEMENT**

The System Operator (SO) shall be responsible for implementing and enforcing the Grid Code. All other Code Participants shall support the SO in its above function, by properly and timely complying with their obligations as defined in the Grid Code during normal operation of the National Grid as well as providing support to the SO in effectively dealing with any unexpected and contingent conditions on the System.

CM 5 **THE GRID CODE REVIEW PANEL**

CM 5.1 SO shall establish and maintain the Grid Code Review Panel (GCRP), which shall be a standing body and shall undertake the functions detailed in CM 5.3.

CM 5.2 The GCRP shall consist of:

(a) Chairman from the SO and one (1) additional member appointed by SO;

(b) Vice Chairman from the National Grid Company (NGC) and one (1) additional member appointed by NGC;

(c) one (1) member from NEPRA;

(d) one (1) member from the Market Operator (MO);

(e) one (1) member from each province representing Provincial Grid Companies of that province;

(f) one (1) member from Special Purpose Transmission Licensees;

(g) one (1) member from each ex-WAPDA Distribution Company and K-Electric;

(h) Six (6) members from large conventional Generators (Thermal, Hydro, Nuclear, etc.);

(i) Four (4) members from Alternative and Renewable Energy Technologies (small Hydro, Solar, Wind, Bagasse, Storage Systems, etc. as defined in ARE Policy 2019);

(j) One (1) member from Bulk Power Consumers (directly-connected with Transmission System);

(k) One (1) member from the industry or an academic institution (on a 3-year rotation basis), nominated by Pakistan Engineering Council.

The detailed rules for representation for each category shall be developed by the GCRP and approved by NEPRA.

CM 5.3 The GCRP shall:

(a) keep the Grid Code and its workings under constant review;

(b) review all requests for Amendments to the Grid Code which NEPRA, the SO, or any Code Participant files with the GCRP or the GCRP initiates at its own;

(c) make recommendations to NEPRA for approval, after deliberation on the requests for Amendment to the Grid Code received pursuant to CM5.3(b);

(d) make appropriate recommendations to NEPRA for approval, after thorough evaluation, any request by any Code Participant seeking for Derogation from any provision(s) of the Grid Code;

(e) publish all the approved Amendments on NEPRA website and incorporate these in the Grid Code, as necessary and practicable;

(f) issue guidance on the Grid Code and its implementation and performance;

(g) issue interpretation on any provision(s) of the Grid Code, when requested by any Code Participant;

(h) resolve any dispute between the SO and any Code Participant; and

(i) consider any modification(s) which may be necessary to the Grid Code arising out of any unforeseen circumstances and Force Majeure, under CM 17 and CM 18 of this sub-code respectively, referred to it by SO or Code Participants.

CM 5.4 The GCRP shall establish and comply with at all times with its own rules and procedures relating to the "Conduct of its Business", which shall be developed by the GCRP within three (3) months of the GCRP's formation and approved by NEPRA.

CM 6 **GRID CODE AMENDMENT AND DEROGATION PROCESS**

CM 6.1 NEPRA shall be the approving authority for the Grid Code, as well as for making any Amendments to it or granting any Derogation from its provisions. For approving any request for Amendment or Derogation, NEPRA will be guided, but not constrained, by the GCRP's recommendations on the relevant matter.

CM 6.2 The Grid Code shall be thoroughly reviewed and revised after every 5 years or earlier as and when required.

CM 6.3 **Grid Code Amendment or Derogation**

CM 6.3.1 All requests for Amendment to or Derogation from the Grid Code shall be submitted to the GCRP, processed and examined by the GCRP, and recommended by the GCRP to NEPRA for final approval.

CM 6.3.2 Any Code Participant, GCRP member, SO, or NEPRA itself may propose Amendment(s) to the Grid Code.

CM 6.3.3 Code Participant can seek Derogation from complying with one or more provisions of the Grid Code which may be considered on the following grounds:

(a) to provide for existing Plant and/or Apparatus that has not been designed in accordance with the provisions of the Grid Code;

(b) to facilitate a smooth transition to the Grid Code from the existing situation; and/or

(c) to ease one or more temporary constraints that prevent compliance and necessitate exemption.

CM 6.3.4 A Code Participant seeking Derogation from the provision(s) of the Grid Code shall make a written request to the GCRP and shall be required to justify the request in terms of both the specific circumstances and the expected duration. As a minimum, the application must include the following information:

(a) detail of the applicant;

(b) relevant provision(s) of the Grid Code and the required performance;

(c) a description of the relevant Plant and/or Apparatus and the nature and extent of non-compliance (where applicable);

(d) a description of the proposal for restoring compliance (where applicable) including details of actions to mitigate risks and restore compliance including timetable;

(e) a description of the reasonable alternative actions that have been considered; and

(f) a statement of the expected duration of the non-compliance.

CM 6.3.5 On receipt of a request for Derogation, the GCRP shall promptly consider such request (by seeking third party advice/opinion on the request, if necessary) and submit its recommendation(s) to NEPRA within three (3) months for a final decision.

CM 6.3.6 NEPRA shall consider the request in light of the recommendation(s) of the GCRP, and shall decide on the request as appropriate. In deciding on the request, NEPRA may invite the applicant or member(s) of GCRP to seek clarification on the request.

CM 6.3.7 NEPRA shall communicate its final decision to the GCRP for informing the applicant and/or for taking further action, as may be appropriate. The GCRP will notify the applicant of NEPRA's decision on its Derogation request accordingly.

CM 6.3.8 If a Derogation is granted, then the relevant Code Participant will not be obliged to comply with the applicable provision(s) of the Grid Code (to the extent and for the period of the Derogation) and shall comply with any alternate provision as set forth in the Derogation.

CM 6.3.9 A Derogation from the Grid Code will have an expiry date in order to review its continued needs and monitor performance towards compliance.

CM 6.3.10 A Derogation granted to a Code Participant shall be non-transferable. Therefore, if in the event of transfer of ownership of Plant and Apparatus of the non-compliant Code Participant, the transferee shall need to seek a new Derogation.

CM 6.3.11 Where a material change in circumstances has occurred, a review of any existing Derogation, and any Derogation under consideration, may be initiated by NEPRA or SO or at the request of Code Participant.

CM 6.3.12 Every Amendment in Grid Code or Derogation granted will be entered on a register maintained by NEPRA for this purpose.

CM 7 **SYSTEM CONTROL**

Where a Code Participant's Plant and Apparatus (or part thereof) is, by agreement, under the SO control, then for the purposes of communication and coordination on operational matters, the SO can (for these purposes only) treat that Code Participant's Plant and Apparatus (or any part thereof) as part of the Transmission System, but as between the SO and Code Participant it will continue to be treated as the Code Participant's Plant and Apparatus.

CM 8 **ASSISTANCE IN IMPLEMENTATION**

CM 8.1 In order to fulfil its duty to implement the Grid Code, the SO may, in certain cases, need access across boundaries, or may need services and/or facilities from Code Participants. This could, for example, include De-Energizing and/or Disconnecting

Plant and Apparatus. Such cases would be exceptional and it is not, therefore, possible to envisage precisely or comprehensively what the SO might reasonably require in order to put it in a position to be able to carry out its duty to implement the Grid Code in these circumstances.

CM 8.2 Accordingly, Code Participants are required to abide by the letter and spirit of the Grid Code by providing the SO with such rights of access, services and facilities as provided for in the appropriate agreements, and complying with such instructions as the SO may reasonably require in implementing the Grid Code.

CM 9 OWNERSHIP OF FACILITIES, PLANT AND APPARATUS

The Facilities, Plant and Apparatus of a Code Participant shall include Facilities, Plant and Apparatus used by the Code Participant under an agreement with a third party. Code Participant shall immediately communicate to SO any changes in Plant and Apparatus that affects (or may affect) the operation of the Transmission System.

CM 10 DEVELOPMENT OF STANDARD OPERATING PROCEDURES

In case where the Grid Code does not specify procedures for any activity mentioned in the Grid Code, Standard Operating Procedures shall be developed by the SO, in consultation with Code Participants.

CM 11 COMMUNICATIONS BETWEEN SO AND CODE PARTICIPANT

CM 11.1 All operational instructions issued by SO to the Code Participant shall be between the SO Control Engineer based at the designated Control Centre, as advised to relevant Code Participant before Connection to the Transmission System, and the Code Participant’s Responsible Engineer based at its control center, notified to the SO before Connection to the Transmission System.

CM 11.2 Unless otherwise specified in the Grid Code, all operational communications shall be through Control Telephony (dedicated telephone networks).

CM 11.3 All non-operational communications (data information and notices) between the SO and Code Participant shall be in writing and issued to the appropriate staff of the SO and the Code Participant.

CM 11.4 If for any reason, the SO or Code Participant re-locates its Control Centre, the SO or Code Participant must inform the other party in writing of the move and any changes to its Control Telephony.

CM 11.5 All instructions and communications given by Control Telephony are to be recorded by whatever means available, kept for at least five (5) years, and shall be acceptable by the SO and Code Participants as evidence of those instructions or communications.

CM 12 INFORMATION DISSEMINATION

CM 12.1 The SO shall establish, operate and maintain a website, providing necessary information about the Transmission System status, congestion, operating procedures, and other relevant information and data. Including all above the SO shall include daily demand and generation status at website.

CM 12.2 The SO/Code Participants shall sign a Non-Disclosure Agreement (NDA) between them and with the external/third parties before disclosing confidential information. The issuance, disclosure and/or publication of any data by SO on its website or otherwise shall be subject to prior classification of data/information on the basis of sensitivity i.e., public, limited/authorized access etc.

CM 13 **CONTRACTS PRIOR TO ENACTMENT OF GRID CODE**

For the agreements that were executed prior to Grid Code coming into force, conditions contained in this Grid Code shall be applicable to such Code Participants which are technically capable, in accordance with the provisions of the Grid Code, to comply with the requirements of the Grid Code.

CM 14 **HIERARCHY**

In the event of any conflict between the provisions of the Grid Code and any contract, agreement, or arrangement between the SO and a Code Participant, the provisions of the Grid Code shall prevail unless the Grid Code expressly provides otherwise.

CM 15 **NON-COMPLIANCE**

Non-compliance of any of the provisions of this Grid Code by the SO or any of the Code participants shall be treated as a violation of the whole Grid Code and shall be subject to penalties as per NEPRA Fees & Fines Rules.

CM 16 **INDEMNITY TO THE SO**

Code Participant shall keep the SO indemnified at all times against any claim, action, damage, loss, liability, expenses or outstanding liability which the SO pays, suffers, incurs or is liable for in respect of any breach by such person or any of its officer, agent or employee.

CM 17 **UNFORESEEN CIRCUMSTANCES**

CM 17.1 If unforeseen circumstances arise which are not included in the Grid Code, the SO shall promptly consult with all affected Code Participants in an effort to reach an agreement on what needs to be done under such circumstances.

CM 17.2 If an agreement between the SO and Code Participant(s) as to what needs to be done cannot be reached in the time available, the SO shall determine what should be done. In any event, the SO will act reasonably and in accordance with Prudent Utility Practice in all circumstances.

CM 17.3 Code Participants shall fully comply with all instructions given to it by the SO following such a determination, provided the instructions are consistent with the then current technical parameters of the Code Participant’s Plant and Apparatus as notified under the Grid Code.

CM 17.4 The SO shall promptly refer all such unforeseen circumstances, and any such determination, to the GCRP as appropriate for consideration in accordance with CM 5.3.

CM 18 **FORCE MAJEURE**

CM 18.1 The SO or a Code Participant (as the case may be) shall not be considered to be in default of its obligation to comply with one or more provisions of the Grid Code if it is prevented from such compliance by Force Majeure. The defaulting party, the SO or the Code Participant (as the case may be), shall give notice and the full particulars of such Force Majeure to NEPRA and the other concerned party (or parties) in writing or by telephone as soon as reasonably possible after the occurrence of the Force Majeure. Telephone notices given shall be confirmed in writing as soon as reasonably possible and shall specifically state full particulars of the Force Majeure, the time and date when the Force Majeure occurred, and when the Force Majeure is reasonably expected to cease. The Code Participants affected shall, however, exercise due diligence and all necessary efforts to remove such disability and fulfil their obligations under the Grid Code.

CM 18.2 Mere economic hardship shall not be considered Force Majeure. Acts of negligence or wrongdoings shall also be excluded from Force Majeure.

CM 19 **ILLEGALITY AND PARTIAL INVALIDITY**

CM 19.1 If any provision of the Grid Code is ruled to be illegal or partially invalid by any applicable court of law for any reason, the legality and validity of all the remaining provisions of the Grid Code shall remain valid.

CM 19.2 If any part of a provision or section of the Grid Code is ruled by any applicable court of law to be unlawful or invalid, the rest of the provision, section, or sub-code shall remain valid, without affecting the meaning or validity of any other provision of the Grid Code.

CM 20 **UNRESOLVED MATTERS AND GRID CODE INTERPRETATION**

CM 20.1 In case a Code Participant is not clear about any particular provision of the Grid Code, that Code Participant may seek interpretation on that provision from the SO. If the Code Participant is not satisfied by the SO’s interpretation, the Code Participant can file a request with the GCRP seeking its guidance. The GCRP will consider the Code Participant’s request in its next scheduled meeting and provide the GCRP’s interpretation to the requesting Code Participant. In case the Code Participant is still not satisfied with the interpretation provided by the GCRP, the Code Participant can seek guidance from NEPRA whose interpretation on that particular provision will be final and binding on the SO as well the Code Participants (including the Code Participant making the request).

CM 20.2 Should a dispute arise between the SO and any Code Participant on any matter pertaining to the implementation of the Grid Code, the SO and Code Participant will try to resolve it amicably between them. If they are unable to resolve it between them within one (1) month, any of them can seek resolution of the dispute through the GCRP. The GCRP will try to mediate between the SO and the Code Participant to resolve it to the satisfaction of both the SO and the Code Participant within three (3) months. If still not resolved, either party can seek resolution of the dispute through the dispute resolution process prescribed by NEPRA.

CM 20.3 The GCRP shall refer to NEPRA any matters requiring interpretation of the Grid Code provisions.

CM 21 **MISCELLANEOUS**

CM 21.1 The provisions of the Grid Code will apply prospectively and shall be mandatory for Code Participants seeking new, or modification of their existing, Connection with the Transmission System. Plant and Apparatus of existing Code Participants may not have been designed in accordance with the provisions of the Grid Code. Such Code Participant shall seek "Derogation" from NEPRA (through the GCRP) for relevant provisions of the Grid Code by following the process described in CM 6. The GCRP will recommend and NEPRA will decide on such requests based on the merit of the case and the evidence provided by the relevant Code Participant for this purpose.

CM 21.2 All laws, regulations, standards, procedures, documents referred to in the Grid Code will include their latest revision that are made to them from time to time.

CM 21.3 The titles, headings, charts and figures included in this Grid Code are provided purely to ease understanding of various provisions of the Grid Code. As such, these shall be ignored for the Grid Code interpretation, compliance, and enforcement.

CM 22 **DATA AND NOTICES**

CM 22.1 References in the Grid Code to 'in writing', shall include typewriting, printing, lithography and other modes of reproducing words in a legible and non-transitory form such as electronic communications.

CM 22.2 Where applicable all data items shall refer to Nominal Voltage and Frequency.

CM 23 **DEFINITIONS**

CM 23.1 When a word or phrase that is defined specifically and in detailed manner in the Definitions section is more particularly defined in another sub-code, the particular definition in that sub-code shall prevail if there is any discrepancy. Such discrepancies, when noticed, will be brought to the notice of the GCRP and will be removed.

CM 23.2 **Mandatory Provisions**

The word "shall" refers to a rule, procedure, requirement, or any other provision of the Grid Code that requires mandatory compliance.

CM 23.3 **Plural and Gender**

In interpreting any provision of the Grid Code:

(a) the singular shall include the plural and vice versa, unless otherwise specified; and

(b) one gender shall include all genders.

CM 23.4 **Person or Entity**

Any reference to a person or entity shall include an individual, partnership, company, corporation, association, organization, institution, or other similar groups.

PLANNING CODE

PC 1. **INTRODUCTION**

The Planning Code specifies responsibilities of Users of the National Grid, data requirements and the integrated system planning (ISP) process by which the objectives of system security, adequacy, reliability, and performance shall be satisfied.

PC 1.1. **Objective**

The key objectives of the Planning Code are:

(a) to specify the responsibilities of the System Operator (SO) and Transmission Network Operators (TNOs) in the planning and development of the National Grid;
(b) to specify the planning data requirements from the Users seeking new Connection or a modification in their existing Connection to the Transmission System; and
(c) to specify the planning standards, procedures and technical studies that shall ensure the safety, security, reliability, and stability of the National Grid.

PC 1.2. **Scope**

This Code applies to SO and the following Users:

(a) Transmission Network Operators (TNOs);

(i) National Grid Company (NGC, currently this is called NTDC)

(ii) Provincial/Regional Grid Companies (PGCs/RGCs)

(iii) Special Purpose Transmission License Companies (SPTLs)

(iv) Distribution Companies (DISCOs)

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

PC 2. **PLANNING RESPONSIBILITIES**

PC 2.1. The System Operator shall be responsible for the following activities:

(a) Preparation of Global Demand Forecast for different growth rates (low, medium and high) based on data provided by the Users.

(b) Preparation of Indicative Generation Capacity Expansion Plan (IGCEP) that shall be developed following the least-cost and optimal generation planning methodologies/processes as well as adhering to the stipulated system reliability criteria;

(c) Preparation of Long-term Transmission Plan (LTP) to ensure bulk Transmission System adequacy to meet the Global/Spatial Demand Forecast after incorporation of the new generation/bulk load facilities;

(d) Performance of the required system studies for incorporating/interconnecting new facilities into the National Grid such as

Generators, bulk loads of 30 MW and above, new transmission lines or substations etc.;

(e) Preparation of an Annual System Reliability Assessment and Improvement Report "ASRAIR" for submission to the NEPRA. The ASRAIR shall identify and evaluate Transmission System congestion problems that may potentially cause restrictions in the economic dispatch and/or may cause load curtailment or raise the cost of service significantly. Correspondingly, the respective TNOs shall recommend remedial measures in their jurisdictions in consultation with the SO before implementation of the proposed solutions;

PC 2.2. TNOs shall be responsible for the following activities:

(a) National Grid Company (NGC) shall prepare a centralized Transmission System Expansion Plan (TSEP) with the coordination of other TNOs.

(b) Conduct Facilities Assessment Studies following the System Impact Assessment Studies.

(c) Preparation of project feasibility study reports justifying the proposed project(s) along with the detailed cost estimate of the recommended transmission facilities;

(d) Performance of the required system studies for incorporating/interconnecting new bulk load facilities with below 30MW demand into their Transmission System.

PC 3. **PLANNING DATA**

The System Operator and TNOs would require different types of data/information from the Users in order to develop system models, conduct the required system studies and develop reinforcement/expansion plans for the National Grid to adequately meet the desired objectives of cost-effectiveness and reliable system operation. This data is collectively known as the Grid Planning Data and it is broadly classified into two categories i.e. Standard Planning Data and Project Planning Data.

PC 3.1. **Standard Planning Data**

PC 3.1.1. The data required from the existing Users at regular intervals (annually) relating to their respective Connection Site(s), as stated in the Appendix part 1 of the Planning Code, shall be treated as Standard Planning Data. This data shall be submitted by 15th January each year and shall cover each of the 10 succeeding years.

PC 3.1.2. Where from the date of one submission to the subsequent date of submission there is no change in the data to be submitted for any given year, instead of resubmitting the data, a User may submit a written statement that there has been no change from the data submitted previously, pertaining to the particular year specified.

PC 3.1.3. Standard Planning Data, together with other data relating to the Transmission System, will provide the basis on which new applications by User(s) will be considered and from which planning of the National Grid will be undertaken. Accordingly, Standard Planning Data will be used for:

(a) Preparation of the Spatial and Global Demand Forecasts;

(b) Preparation of Indicative Generation Capacity Expansion Plan (IGCEP);

(c) Preparation of Long-term Transmission Plan (LTP); and

(d) Preparation of Transmission System Expansion Plan (TSEP).

PC 3.2. **Project Planning Data**

A new or existing User shall supply data under the Planning Code in relation to the proposed new Connection Site or Modification to the existing connection. Such Data/information will be considered as the Project Planning Data, which is further classified into the following three sub-categories:

PC 3.2.1. **Preliminary Data**

At the time the User applies for a Connection (Intent Application), but before such an offer is made, the data relating to the proposed User Development will be considered as Preliminary Data. This data will be treated as confidential within the scope of the policy on confidentiality as per DRC.

PC 3.2.2. **Committed Data**

Once the "Offer to Connect" has been formally accepted by the prospective User, the data relating to the User Development, already submitted as Preliminary Data, and any subsequent data required and submitted by the User as stated in the Appendix part 2 of this Code, will become Committed Data. This data, together with other data relating to the Transmission System, will provide the basis on which new applications by any User will be considered and from which planning of the Transmission System and power system analysis will be undertaken. Accordingly, Committed Data shall not be treated as confidential to the extent that the SO (or any other relevant entity) is obliged to use or disclose these to discharge its contractual or regulatory obligations.

PC 3.2.3. **Registered Data**

The Planning Code requires that, as soon as is practical, and not later than a date which is the earlier of 18 months prior to the firm Connection Date or six months after the signing of the Connection Agreement, unless otherwise directed by the NEPRA, all data requirements as stated in the Appendix part 2 of the Planning Code, not previously required by the SO/TNOs and/or supplied by the User, will be submitted by the User to the SO/TNOs. This will include confirming any estimated values/parameters assumed for planning purposes or, where practical, replacing them with validated actual values/parameters and by updating the Forecast Data items such as Demand. Data provided at this stage of the project shall become Registered Data.

PC 3.2.4. **Data Validation and Verification**

PC 3.2.4.1. Where a User submits data, which in the opinion of the SO/TNOs is incorrect or insufficient then the SO/TNOs shall require that User supply such additional information as the SO/TNOs deems necessary to verify the accuracy of the data. If

SO/TNOs consider that the additional information is still insufficient to verify the accuracy of the original data, then the SO/TNOs may request that the User carry out specific Test(s) to verify the data or validate it from reliable third party the costs of which shall be borne by the User (irrespective of the test results). Where such Tests or Validations are requested, they will be subject to the provisions of OC 11.

PC 3.2.4.2. In the event that any of the data items submitted by the User are found to be incorrect or inaccurate then the User shall also bear the additional costs of the studies which SO shall perform using the data values as ascertained by the Test(s). However, in the case where test results validate the data provided by the User the additional cost of the studies shall not be borne by the User.

PC 4. **INTEGRATED SYSTEM PLAN**

SO in association with Transmission Network Operators shall develop an Integrated System Plan based on the Grid Planning Data outlined in PC 3. Standard planning activities and their corresponding processes are described below.

PC 4.1. **Demand Forecasting**

Two types of demand forecasts shall be prepared for the Users of National Grid;

PC 4.1.1. Spatial Forecast shall be prepared annually for a horizon of 10 years based on the Power Market Survey (PMS) approach. SO will consolidate the area demand forecasts prepared by the respective DISCOs. The area demand forecasts would be used by TNOs and DISCOs for preparing Investment Plans (network reinforcement and expansion) for their respective Service Territories.

PC 4.1.2. Global Forecast shall be prepared by System Operator for three growth levels (Low, Medium, High) based on the econometric modelling approach. This forecast shall be prepared every 2 years for a horizon of at least 20 years. The econometric model shall take into account the economic activity, population trends, industrialization, DISCOs forecasts, demand side management and any other potential variable that may affect the load growth such as embedded/distributed generation and Electric Vehicles (EVs), etc. System Operator shall use this forecast in developing the IGCEP and LTP.

PC 4.2. **Generation Plan**

PC 4.2.1. System Operator shall prepare an "Indicative Generation Capacity Expansion Plan" (IGCEP) based on the least-cost principle to meet the Global Load Forecast. IGCEP shall be prepared every 2 years for a horizon of 15 years.

PC 4.2.2. The IGCEP shall satisfy Loss of Load Probability (LOLP) and/or Reserve Margin (RM) criteria. LOLP and RM should not exceed 1% and 10% per year, respectively. RM shall be capped at 10% in case it exceeds to satisfy 1% LOLP criteria. NEPRA may revise the LOLP and RM criteria from time to time.

PC 4.2.3. The IGCEP shall identify any new capacity requirements by type, size, location and year-by-year development sequence along with their commissioning dates by taking into account the capacity retirements, annual outage periods, generation capacity upgrades, plants whose PPAs are expiring and transmission system aspects.

PC 4.3. **National Grid Expansion Plans**

PC 4.3.1. System Operator shall prepare LTP in conjunction with the IGCEP and Global Demand Forecast in such a way that the total cost of integrated system plan is optimized. LTP shall recommend bulk transmission system expansion requirements along with the budgetary cost estimates, which shall be prepared every 2 years for a horizon of 15 years.

PC 4.3.2. Together, IGCEP and LTP, which are prepared based on the Global Demand Forecast, constitute an Integrated System Plan (ISP) for a horizon of 15 years. The IGCEP and LTP (ISP) shall be submitted to NEPRA by 15th of April after every 2 years for approval.

PC 4.3.3. National Grid Company shall prepare a centralized Transmission System Expansion Plan (TSEP) based on Spatial Demand Forecast in view of the ISP (IGCEP and LTP) with the coordination of other TNOs. TSEP shall be prepared annually for a horizon of at least 5 years.

PC 4.3.4. TSEP shall recommend specific transmission system reinforcements, upgradation, and expansion projects and evaluate the corresponding investment requirements, which are calculated based on the preliminary/feasibility cost estimates. TNOs shall prepare their respective Transmission Investment Plans for a horizon of at least 3 years. These plans shall specify year-by-year investment requirements for developing the required transmission facilities along with their commissioning dates. TSEP shall be submitted to NEPRA by 15th May each year for approval.

PC 4.3.5. The identified transmission system requirements (LTP or TSEP) shall be proposed based on the stipulated technical criteria mentioned in the "Transmission Planning Criteria & Standards" (TPCS) document. The proposed transmission system projects may entail: new transmission lines, new grid stations, new transformer installations, extension/augmentation of transformers and sub-stations including bus expansions, reactive power compensation equipment (shunt and/or series compensation), power quality compensation equipment and upgradation of switchgear etc.

PC 4.3.6. The transmission system reinforcement/expansion plans shall be prepared in a well-coordinated effort of the planning teams of SO and TNOs.

PC 4.4. **System Impact Assessment Studies**

PC 4.4.1. SO shall perform or cause to perform the Feasibility Study after receiving the Intention Application package from the User seeking a new connection or modification to its existing connection in accordance with the procedure laid out in CC 2. Feasibility Study scope shall include evaluation of the possible connection option(s) and availability of transmission capacity (based on the load flow analysis) as well as providing budgetary cost estimates. The outcome of the Feasibility study will establish most feasible connection option as input to the Grid Impact Study.

PC 4.4.2. SO shall perform or cause to perform the Grid Impact Study (Load Flow, Short Circuit and Transient Stability Studies as well as any advanced analytical study deemed necessary) on the identified/feasible connection option after receiving the Formal Application package in accordance with the procedure laid out in CC 2. Grid Impact Study (GIS) scope, to be developed in association with the respective

TNO, shall include the evaluation and recommendation of the most appropriate transmission interconnection, system reinforcement and expansion requirements after the incorporation of the User’s project development without compromising security and stability of the integrated power system.

PC 4.4.3. GIS results shall be shared with the respective TNO to which the User’s project is being connected. Subsequently, TNO shall perform or cause to perform the required Facility Assessment Study to quantify the changes/modifications as well as the reinforcement facilities that it has to implement in its transmission network after incorporation of the User’s project. TNO shall also provide a detailed cost estimate to the User for the proposed transmission interconnection and reinforcement facilities.

PC 4.4.4. SO, TNO or User may conduct the required System Impact Assessment Studies in-house or may engage any eligible consultant to perform these studies in compliance with the standards defined in the “Transmission Planning Criteria & Standards” (TPCS) document.

PC 4.4.5. SO shall perform or cause to perform Feasibility and Grid Impact Studies, in coordination with respective TNOs, for all the User’s project(s) to be connected at Transmission Voltage except Demand Users with aggregated demand of 30MW or below.

PC 4.4.6. System Impact Assessment Studies for Demand Users to be connected at Transmission Voltage with aggregated demand of 30MW or below shall be arranged by respective TNO(s) in coordination with SO.

PC 4.4.7. User’s projects connecting at Distribution Voltage shall be reviewed and approved by the relevant DISCOs.

PC 5. **PLANNING CRITERIA AND STANDARDS**

Transmission Planning Criteria and Standards (TPCS) document defines all the criteria and standards according to which planning activities shall be performed, attached as Annexure 1.

APPENDICES

The appendices specify the data to be submitted to the **SO** by **Users** or prospective **Users** of the **Transmission System**. The requirement to provide data is governed by the Planning Code PC 3.

The specific data requirements depend on whether the **User** is a **Customer** or a **Generator** or **Interconnector/HVDC** or an External Party in general or more than one combined. Appendices have following two parts;

Part-1 Standard Planning Data

PC.A1 Applies to **all Users**

PC.A2 Applies to **all Users**

Part-2 Project Planning Data

PC.A3 Applies to **Generators**

PC.A4 Applies to **Controllable Solar, Wind and ESPP**

PC.A5 Applies to **Interconnector/HVDC**

Any material changes to the data specified in PC.A3, PC.A4, PC.A 5 must be notified to the **SO** as soon as practicable.

APPENDIX PART-1 STANDARD PLANNING DATA

PC. A1 GENERAL INFORMATION

All Users connected directly through existing Connection Points to the Transmission System or DISCOs seeking a direct Connection shall provide (TNOs/DISCO), the data on their Systems, which relates to the Connection Site which may have an effect on the performance of TNO or DISCOs Transmission System.

PC. A 1.1 Full name of the User(s)

PC. A 1.2 Address of the User(s)

PC. A 1.3 Contact Person

PC. A 1.4 Telephone Number

PC. A 1.5 Telefax Number

PC. A 1.6 Email Address

PC. A2 USER'S SYSTEM DATA

PC. A 2.1 Map and Diagrams

Provide a 1:50,000 Survey map, with the location of the facility clearly marked with an "X". In addition, please specify the Survey Grid Co-ordinates of the electrical connection point, which is assumed to be at the HV bushings of the Grid Connected Transformer.

PC. A 2.2 Provide a plan of the site (1:200 or 1:500) of the proposed facility, indicating the proposed location for a transmission station compound, location of the connection point, generators, transformers, converter stations, site buildings etc. The plan is to be submitted in hard and soft copy format. A digitized format may be required and should also be provided if available.

PC. A 2.3 Licensing and Authorization (For Generation and other applications requested by the SO)

PC. A 2.3.1 Licensee

Details of any **Generation** or **Interconnector/HVDC** or **Supply Licensee** held by the applicant, or of any application for a **Generation** or **Interconnector/HVDC** or **Supply licensee**.

PC. A 2.3.2 Authorization

Details of any authorization or application for authorization to construct or reconstruct the Generation station, Interconnector/HVDC or other applications requested by the SO for which the connection is being sought.

PC. A 2.4 User's System Layout

PC. A 2.4.1 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.

PC. A 2.4.2 The Single Line Diagram must include all parts of the User System operating at Transmission Voltage at any User's Site. In addition, the Single Line Diagram must include all parts of the User's sub-transmission system.

If SO require, the Single Line Diagram must also contain additional details of the User's sub-transmission System not already included above, and also details of the transformers connecting the User's sub-transmission system to a lower voltage.

PC. A 2.4.3 The Single Line Diagram shall also include:

(a) Electrical circuitry identifying overhead lines, underground cables, power transformers reactive compensation equipment and similar equipment etc.

(b) Name of the sub-station with operating voltages.

(c) Circuit breakers isolators, current transformers, potential transformers, protection data.

PC. A 2.4.4 For each circuit shown on the Single Line Diagram, the User shall provide the following circuit parameters details relating to that part of its system:

Circuit Parameters

(a) Rated voltage (kV)

(c) Line Length (km)

(d) Conductor Name & no. of bundles.

(e) Type of Tower

(f) Positive phase sequence reactance

(g) Positive phase sequence resistance

(h) Positive phase sequence susceptance

(i) Zero phase sequence reactance

(j) Zero phase sequence resistance

(k) Zero phase sequence susceptance

(l) Thermal Limits/Surge Impedance Loading of conductor.

PC. A 2.4.5 For each transformer shown on the Single Line Diagram, the User shall provide the following details:

(a) Rated MVA

(b) Voltage Ratio

(c) Winding arrangement

(d) Percentage Impedance

(e) Positive sequence reactance for all windings

(f) Positive sequence resistance for all windings

(g) Zero sequence reactance for all windings

(h) Vector Group

PC. A 2.4.6 In addition, for all interconnecting transformers of the User(s) connected to the Transmission System shall supply the following information:

(a) Earthing system details i.e. direct, resistance or reactance impedance (if not directly earthed).

(b) Tap changer range

(c) Tap change step size

(d) Tap changer type

PC. A 2.4.7 User shall supply the following information about the User's equipment installed at a Connection Site, which is owned, operated or managed by TNO/DISCO:

(a) Switchgear: User shall provide the following parameters for the circuit breakers.

(i) Rated Voltage (kV)

(ii) Operating Voltage (kV)

(iii) Rated 3-phase rms short-circuit breaking current, (kA)

(iv) Rated 1-phase rms short-circuit breaking current, (kA)

(v) Rated 3-phase peak short-circuit making current, (kA)

(vi) Rated 1-phase peak short-circuit making current, (kA)

(vii) Rated rms continuous current (A)

(viii) DC time constant applied at testing of asymmetrical breaking abilities ("seconds" or "s".)

(b) Substation Infrastructure: User shall provide the following parameters for the installed electrical equipment.

(i) Rated 3-phase rms short-circuit withstand current, (kA)

(ii) Rated 1-phase rms short circuit withstand current, (kA)

(iii) Rated 3-phase short-circuit peak withstand current, (kA)

(iv) Rated 1-phase short-circuit peak withstand current, (kA)

(v) Rated duration of short circuit withstand (Secs)

(vi) Rated rms continuous current (A)

(c) Detailed short circuit data for single-point or multi-point connection sites.

PC. A 2.4.8 **Lumped System Susceptance**

For all parts of the User's Sub-Transmission System, which are not included in the Single Line Diagram provided under PC.A.2.1.1, each User shall provide the equivalent lumped shunt susceptance at Nominal frequency.

PC. A 2.4.9 Reactive Compensation Equipment

For all independently switched reactive power compensation equipment, including that shown on the Single Line Diagram, not owned by TNO/DISCO and connected to the User's System at 132 kV and above, other than power factor correction equipment associated directly with User's Plant and Apparatus, the User shall supply the following information.

(a) Type of equipment (e.g. fixed or switched or variable);

(b) Capacitance 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 Connection Point to the User's system in terms of electrical location and system voltage; and

(e) Voltage assessment studies of the User system if it is a generator of weak reactive power capability or if it is a load of high reactive demand causing Power Quality issues e.g. arc furnace etc. (with and without reactive compensation equipment)

PC. A 2.4.10 Short Circuit Contribution to TNO/DISCO Transmission System

General

(a) To allow TNO/DISCO .to calculate fault currents, each User is required to provide data and short circuit analysis of its system; calculated in accordance with IEC 60909, as set out in the following paragraphs.

(b) The data should be provided for the User's system with all Generating Units synchronized to the User's System. 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. 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 current in sub-paragraphs (a) and (b) of the data list should be based on an AC load flow that takes into account any pre-fault current flow across the Connection Point being considered. Measurements made under appropriate system conditions may be used by the User to obtain the relevant data.

(d) TNO/DISCO may at any time, in writing, specifically request for data to be provided for any alternative system condition, for example minimum plant, and the User will provide the information as soon as reasonably practicable following the request.

Generator’s Data for Short Circuit Calculations

For each Generating Unit with one or more associated Station Transformers, the Generator is required to provide values for the contribution of the Generator auxiliaries (including auxiliary gas turbines or auxiliary diesel engines) to the fault current flowing through the Station Transformer(s).

(a) Root mean square of the symmetrical three-phase short circuit current in feed at the instant of fault:

(b) Root means square of the symmetrical three-phase short circuit after the sub-transient fault current contribution has substantially decayed;

(c) If the associated generating unit step-up-transformer can supply zero phase sequence current from the generating unit side to the TNO/DISCO Transmission System;

(d) If the value is not 1.0 p.u. as per IEC 60909;

(e) Root mean square of the pre-fault voltage at which the maximum fault currents were calculated.

If the Generator 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: -

Data for the fault in feeds through both Step-up Transformers and Stations Transformers shall be provided for the normal running arrangement when the maximum number of Generating Units in the Power Station are synchronized to the System.

Data Items

(a) The following is the list of data utilized in this part of the Planning Code.

  (i) Root mean square of the symmetrical three-phase short circuit current in feed at the instant of fault;

  (ii) Root mean square of the symmetrical three-phase short circuit after the sub-transient fault current contribution has substantially decayed;

  (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;

  (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; and

  (vi) The negative sequence resistance and reactance values of the User's System seen from the node on the Single Line Diagram

PC. A2.5 Data Required for Demand Forecasting

1. Data for Spatial demand forecasting which includes (but not limited to);

   a. DISCOs level data;

      i. Annual Recorded and Computed Peak Demand with Month, Date and Time

      ii. Annual Electricity Consumption (GWh) by category;

      iii. Annual Distribution Losses;

iv. Annual Secondary transmission losses (132 kV);

v. Future Loss reduction plan of DISCOs;

b. Substation level data;

i. Sub-station wise Peak Demand with Substation Name and unique identifier;

ii. Coincidence factor;

iii. Relevant Data of Proposed Sub-stations;

c. 11kV Feeder level data;

i. Feeder code, name and category;

ii. Category-wise Planned Load;

iii. Category-wise Pending Load;

iv. Captive Load (kW and kWh);

v. Net metering / roof top solar data;

2. Data for Global demand forecasting which includes (but not limited to);

a. Annual Energy Generation (GWh);

b. Category-wise Energy consumption (GWh);

c. Recorded and Computed Peak Demand (MW);

d. Hourly load data

e. Yearly System Losses;

i. Primary and secondary Transmission losses;

ii. Distribution System losses;

f. Electricity Average Price (Rs. /kWh) by category;

g. Historical and Projected Sector-wise Gross Domestic Product (GDP);

h. Load Shedding/Load Management data;

i. Demand side management targets by NEECA;

j. Category-wise Number of Consumers

k. Historical and Projected Population of Country

Based on the above data, Active Power (MW) and Active Energy Requirements (MWHs) of the system shall be calculated.

PC. A2.6 Data Required for Indicative Generation Capacity Expansion Plan

Table PC.A-1 Data Requirement of Bagasse based Generator for IGCEP

BAGASSE	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Type of Project	
Installed Capacity (MW)	
Auxiliary Capacity (MW)	
Nature of Project	
Status of Project	
Year of Approval of Feasibility Study	
Location of project	
Proposed Interconnection Voltage level (kV)	
Dispatching Arrangement	
Construction start date	
Percentage of work completed (%)	
Earliest date of availability/ Expected Commissioning date of 1st unit	
Construction period (months)	
Economic Life (years)	
De-commissioning date	
PPA expiry date	
Fuel Type	
Unit of Fuel Rate	
Fuel Rate	
Unit of Heating Value	
Heating Value of Fuel	
Capacity of each Unit (n) (MW)	
Total number of units	

Annual Capacity Factor for export to grid (%)	
Schedule Maintenance Time Annual (days)	
Forced outage rate annual (%)	
Mean time to repair during forced outage (Hours)	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to ________ PKR)	
Monthly Total Energy	
Monthly Peak Capability	
Any other information	

Table PC.A-2Data Requirement of Batteries for IGCEP

BATTERIES	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Type of Batteries	
Installed Capacity of Project (MW)	
Storage Capacity of Project (MWh)	
Nature of Project	
Status of Project	
Location of project	

Proposed Interconnection Voltage level (kV)	
Dispatching Arrangement	
Construction start date	
Percentage of work completed (%)	
Construction period (months)	
Earliest date of availability/ Expected COD	
Economic Life (years)	
De-commissioning date	
Max Power Export to Grid (MW)	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%)	
Maximum Cycles	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to _______ PKR)	
Any other information	

Table PC.A-3 Data Requirement of Hydro Generator for IGCEP

HYDRO	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Installed Capacity (MW)	
Nature of Project	
Status of Project	
Year of Approval of Feasibility Study	
Location of project	
Type of Project	
Proposed Interconnection Voltage level (kV)	
Dispatching Arrangement	
Construction start date	
Percentage of work completed (%)	
Construction period (months)	
Earliest date of availability/ Expected Commissioning date of 1st unit	
Commissioning date of each unit	
Economic Life (years)	
De-commissioning date	
Capacity of Each Unit	
Total number of units	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Annual Schedule Maintenance Time (days)	
Forced outage rate annual (%)	
Mean time to repair during forced outage (Hours)	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	

Storage Capacity (GWh)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to _______ PKR)	
Monthly Total Energy (GWh) (Average Season)	
Monthly Minimum/Base Energy (GWh) (Average Season)	
Monthly Maximum Capability (MW) (Average Season)	
Monthly Total Energy (GWh) (Wet Season)	
Monthly Minimum/Base Energy (GWh) (Wet Season)	
Monthly Maximum Capability (MW) (Wet Season)	
Monthly Total Energy (GWh) (Dry Season)	
Monthly Minimum/Base Energy (GWh) (Dry Season)	
Monthly Maximum Capability (MW) (Dry Season)	
Any other information	

Table PC.A-4 Data Requirement of Solar Generator for IGCEP

SOLAR	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Installed Capacity (MW)	
Nature of Project	
Status of Project	
Location of project	
Proposed Interconnection voltage level (kV)	
Dispatching Arrangement	
Construction start date	
Percentage of work completed (%)	
Earliest date of availability/ Expected Commissioning date of 1st unit	
Construction period (months)	
Economic Life (years)	
De-commissioning date	
Annual Capacity Factor for export to grid (%)	
Annual Degradation Factor (%)	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to _______ PKR)	

Battery (or other storage) connected (Yes/No)	
Type of Batteries	
Installed Capacity of Project (MW)	
Storage Capacity of Project (MWh)	
Expected COD of BESS	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%)	
Maximum Cycles	
Technical Life (Years)	
Fixed O&M Cost $/kW-year	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to _______ PKR)	

Table PC.A-5 Data Requirement of Wind Generator for IGCEP

WIND	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Installed Capacity (MW)	
Nature of Project	
Status of Project	
Location of project	
Proposed Interconnection voltage level (kV)	
Dispatching Arrangement	
Construction start date	
Percentage of work completed (%)	
Earliest date of availability/ Expected Commissioning date of 1st unit	
Construction period (months)	
Economic Life (years)	
De-commissioning date	
Annual Capacity Factor for export to grid (%)	
Number of Turbines	
Capacity of each turbine (MW)	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	
Capital Cost with IDC (Local Component) million USD	
Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	

Dollar Conversion Rate (1 USD to _______ PKR)	
Battery (or other storage) connected (Yes/No)	
Type of Batteries	
2. Installed Capacity of Project (MW)	
Storage Capacity of Project (MWh)	
Expected COD of BESS	
Charge Efficiency (%)	
Discharge Efficiency (%)	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Maximum State of Charge (SoC) (%)	
Depth of Discharge (%)	
Per cycle power (MW) Degradation Factor (%)	
Per Cycle capacity (MWh) Degradation factor (%)	
Maximum Cycles	
Technical Life (Years)	
2. Fixed O&M Cost $/kW-year	
2. Capital Cost with IDC (Local Component) million USD	
2. Capital Cost with IDC (Foreign Component) million USD	
2. Capital Cost with IDC (Total) million USD	
2. Capital Cost without IDC (Local Component) million USD	
2. Capital Cost without IDC (Foreign Component) million USD	
2. Capital Cost without IDC (Total) million USD	
2. Year of Cost Calculations	
2. Dollar Conversion Rate (1 USD to _______ PKR)	

Table PC.A-6 Data Requirement of Thermal Generator for IGCEP

THERMAL	
Particulars	**Details**
Project Executing Entity	
Name	
Designation	
Contact number	
Email	
Name of Project	
Type of Project	
Installed Capacity (MW) Nominal Rating (MW) Maximum Rating (MW)	
De-rated / Dependable Capacity (MW)	
Auxiliary Capacity (MW)	
Nature of Project	
Status of Project	
Location of project (Nearest town)	
Proposed Interconnection Voltage level (kV)	
Dispatch Arrangement	
Construction start date	
Percentage of work completed (%)	
Construction period (months)	
Earliest date of availability/ Expected Commissioning date of 1st unit	
Commissioning date of Each Unit	
Economic Life (years)	
De-commissioning date	
PPA expiry date	
Fuel Type	
Unit of Fuel Price	
Fuel Price	
Unit of Heating Value	
Heating value	

Fuel price calculation year	
Fuel Price Escalation/De-escalation (%)	
Take or Pay contract (%) (if any)	
Take or Pay contract expiry date	
Unit of Fuel price if Take or Pay Contract cannot be met	
Reduced Fuel price if Take or Pay Contract cannot be met	
Annual Take or Pay Contract Quantity (TJ)	
Capacity of Each Unit	
Technology of Each Unit	
Total number of units	
Minimum Stable Level (MW)	
CCGT configuration	
Ramp Up Rate (MW/min)	
Ramp Down Rate (MW/min)	
Minimum Up Time (hours)	
Minimum Down Time (hours)	
Efficiency at Minimum Stable Level (%)	
Efficiency at Full Load (%)	
Heat Rate at 25% Load (BTU/kWh)	
Heat Rate at 40% Load (BTU/kWh)	
Heat Rate at 50% Load (BTU/kWh)	
Heat Rate at 60% Load (BTU/kWh)	
Heat Rate at 70% Load (BTU/kWh)	
Heat Rate at 80% Load (BTU/kWh)	
Heat Rate at 90% Load (BTU/kWh)	
Heat Rate at 100% Load (BTU/kWh)	
Schedule Maintenance Time Annual (days)	
Forced outage rate annual (%)	
Mean time to repair during forced outage (Hours)	
Emission production rate (gCO2/MWh)	
Variable O&M (USD/MWh)	
Fixed O&M (USD/kW-year)	
Capital Cost with IDC (Local Component) million USD	

Capital Cost with IDC (Foreign Component) million USD	
Capital Cost with IDC (Total) million USD	
Capital Cost without IDC (Local Component) million USD	
Capital Cost without IDC (Foreign Component) million USD	
Capital Cost without IDC (Total) million USD	
Year of Cost Calculations	
Dollar Conversion Rate (1 USD to _______ PKR)	
Any other information	
Year of Approval of Feasibility Study	

PC. A3 GENERATOR DATA

PC. A3.1 Generator Unit Details

Each **Generator** shall submit to the **SO** detailed information as required to plan, design, construct and operate the **Transmission System**.

Table PC.A-7Data Requirement of Generators for IGCEP

Generator Data		
Sr. #	**Descriptions**	**Data**
	Expected COD	
	Coordinates of the Project	
	Fuel Type	
	Generator Basic Data	
	Generation Voltage Level (kV)	
	No. of generating units	
	Power factor (Lagging/Leading) of generating unit	
	Rated Apparent Power of each generating unit (MVA)	
	Gross Output of each unit (MW)	
	Maximum Output in Summer and Winter (Peak and Off-Peak)	
	Total Auxiliary Load (MW) / Auxiliary Load with each unit	
	Net Output of each generating unit (MW)	
	Power factor for Auxiliary Load	
	RPM of the machine	
	Total Inertia Constant H for entire rotating mass (MW-s/MVA) – (Generator + Turbine + Rotating Exciter)	
	Short circuit ratio of each generating unit	
Reactance's for Generator (pu)		
	Direct Axis Sub-Transient Reactance (X"d) (unsaturated)	
	Direct Axis Sub-Transient Reactance (X"d) (saturated)	
	Quadrature Axis Sub-Transient Reactance (X"q) (Unsaturated)	
	Quadrature Axis Sub-Transient Reactance (X"q) (saturated)	
	Direct Axis Transient Reactance (X'd) (unsaturated)	
	Direct Axis Transient Reactance (X'd)(saturated)	

	Quadrature Axis Transient Reactance (X'q) (unsaturated)		
	Quadrature Axis Transient Reactance (X'q) (saturated)		
	Direct Axis Synchronous Reactance Xd		
	Quadrature Axis Synchronous Reactance Xq		
	Leakage Reactance Xl(unsaturated)		
	Leakage Reactance Xl(saturated)		
	Negative sequence Reactance X2 (unsaturated)		
	Negative sequence Reactance X2 (saturated)		
	Zero-Phase Sequence Reactance X0 (unsaturated) X0		
	Zero-Phase Sequence Reactance X0 (saturated) X0		
	Time Constants for Generator (s)		
	Transient Direct-Axis Open-Circuit Time Constant T'do		
	Transient Quadrature-Axis Open-Circuit Time Constant T'qo		
	Transient Direct-Axis Short-Circuit Time Constant T'd		
	Transient Quadrature-Axis Short-Circuit Time Constant T'q		
	Sub-Transient Direct-Axis Open-Circuit Time Constant T"do		
	Sub-Transient Quadrature-Axis Open-Circuit Time Constant T"qo		
	Sub-Transient Direct-Axis Short-Circuit Time Constant T"d		
	Sub-Transient Quadrature-Axis Short-Circuit Time Constant T"q		
	Other Factors		
	Saturation Factors of Generator	S (1.0)	
		S (1.2)	
	Characteristic Curves (Saturation, PQ, V-Curve)		
	Generator Step-Up (GSU) Transformers		
	Voltage Rating of GSU transformer (kV)		
	Vector Group		
	No. of transformers and generators connected to each transformer		
	Transformer Rated Power (MVA)		
	Type		
	Percentage Impedance, (R,X) in % at rated MVA base		
	Total Number of Taps		
	Principal Tap Number		

	Earthing Specifications	
	Type of Earthing for Generator (Direct, impedance, transformer)	
	MVA Rating of transformer	
	Voltage Ratio of transformer	
	Transformer Impedance Grounding (R,X) (ohm/PU)	

PC. A3.2 Excitation System Parameters

Provide parameters and supply a Laplace-domain control block diagram (or as otherwise agreed with the **SO**) completely specifying all time constants and gains to fully explain the transfer function from the compensator or generator terminal voltage and field current to generator field voltage. These parameters may include but are not limited to:

Table PC.A-8 Data Requirement of Exciters for GIS

Description	Data
Excitation system type (AC or DC)	
Excitation feeding arrangement (solid or shunt)	
Excitation system Filter time constant – Tr	
Excitation system Lead time constant - Tc	
Excitation system Lag time constant - Tb	
Excitation system Controller gain - Ka	
Excitation system controller lag time constant - Ta	
Excitation system Maximum controller output - Vmax	
Excitation system minimum controller output - Vmin	
Excitation system regulation factor - Kc	
Excitation system rate feedback gain - Kf	
Excitation system rate feedback time constant - Tf	

For Simulation purpose, the model of the exciter would also be required in IEEE or PTI's PSS/E format.

PC. A3.3 Speed Governor System

Supply a Laplace-domain control block diagram and associated parameters of prime mover models for thermal and hydro units (or as otherwise agreed with the **SO**) completely specifying all time constants, gains, droop settings etc. to fully explain the transfer function for the **Governor Control System**.

For Simulation purpose, the model of the speed governor system would also be required in IEEE or PTI's PSS/E format.

PC. A3.4 Power System Stabilizers

Supply a Laplace-domain control diagram and associated parameters for any outstanding control devices including Power System Stabilizer in the generating unit. Some of the critical parameters that are required are:

- Type of input(s);
- Gain for each input;
- Lead Time constant(s) for each input;
- Lag Time constant(s) for each input;
- Power System Stabilizer Model (in IEEE or PTI's PSS/E format)

PC. A 4 Controllable Solar, Wind and ESPP (SWE) Data Requirements

All information for **Controllable SWE** connection applications shall include details of the **Transmission System Connection Point**. This shall include details listed in **PC. A 2.1**, **PC. A 2.2** for the **Connection Point**. The minimum technical, design and operational criteria to be met by **Controllable SWE** are specified in the **Connection Code**.

PC. A 4.1 SWE Generators Parameters

The User shall provide electrical parameters related to the performance of the **Controllable SWE**. This may include but is not limited to parameters of electrical generator, power electronic converters, electrical control and/or protection systems. For WTG, State whether turbines are Fixed Speed or Variable Speed. Also provide the Type of WTG i.e. Type-1, Type-2 (Single Fed Induction Generators), Type-3 (Doubly Fed Induction Generator), Type-4 (Full Converter) or else.

Laplace diagrams and associated parameters shall be provided to the **SO** where appropriate. For Simulation purpose, the Electrical model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format. A sample data sheet for the basic parameters related to wind turbine generators and solar generators are provided below:

Table PC.A-9 Data Requirement of WTG for GIS

Sr. #	Wind Turbine Generator (WTG) Data	
	Expected COD of Generator	
	Generation Type	
	No. of WTGs	
	Manufacturer/Model	
	Gross Capacity of each WTG (MW)	
	Type of WTG	
	Generation Voltage (kV)	
	Power Factor (Lagging/Leading)	
	Ramp Up/Down Rate (MW/Min) or (% /Min)	
WTG Arrangement in Wind Farm		

	No. of Collector Groups	
	No. of WTGs in one collector group	
	Length of each collector group within the switchyard (km)	
Total Wind Farm Capacity		
	Total Gross Capacity (MW)	
	EBOP Losses (MW)	
	Auxiliary Consumption (MW)	
	Total Net Output Capacity that will flow to the grid (MW)	
Generator Step Up Transformer Data		
	No. of step up transformers	
	Voltage Ratio (kV)	
	MVA Rating	
	Percentage Impedance %	
	Vector Group	
Proposed Switchyard of Wind Power Project		
	High Level (HV) Voltage	
	Medium Level (MV) Voltage	
	Proposed Bus Bar Scheme	
	Proposed Bus Bar Capacity (Amp)	
	Proposed Circuit Breaker Capacity at HV Level (kA)	
Power Transformer from HV to MV Level		
	No. of transformers	
	Voltage Ratio (kV)	
	MVA Rating	
	Percentage Impedance %	
	Vector Group	
Proposed Reactive Power Compensation		
	Proposed size of SVC/Switched Shunt Capacitor Bank (MVAR) installed at MV or HV	
Miscellaneous		
	Proposed reactance for each collector group X"d (pu)	

Table PC.A-10 Data Requirement of Solar Generator for GIS

Sr. #	Solar Generator Data	
	Expected COD	
	Generation Type	
	Generation Voltage Level (kV)	
	Medium Voltage Level (kV)	
	High Voltage Level (kV)	
	No. of inverter units	
	No. of Clusters made for Inverters	
	AC Cable Lengths (km)	
	Power factor	
	DC power Connected to each unit (MW)	
	AC power output of each unit (MW)	
	Rated Apparent Power of each inverter unit (MVA)	
	Total Installed DC Capacity of Plant, (MW)	
	Gross AC Output of the Plant, (MW)	
	Reactive Power Compensation Requirement (MVAR) SVC/Switched shunt Capacitor Bank, installed at MV or HV	
	Ramp Up/Down Rate (MW/Min) or (% /Min)	
GSU Transformers		
	No. of GSU transformers (MV/LV kV)	
	Transformer Rated Power, MVA	
	Vector Group	
	Percentage Impedance	
Step-up Power Transformer for Grid End		
	No. of GSU transformers (HV/MV kV)	
	Transformer Rated Power, MVA	
	Vector Group	
	Percentage Impedance	

Note: Most of the initial planning studies of WTGs are carried out using the generic models in PSS/E format. Therefore, WTGs shall submit their Users' specific controller models in PSS/E format of proposed WTGs once the manufactures provide this data to such Users. If Users' specific data is significantly different from the generic model, then the studies shall be carried out again and charges of studies shall be borne by these Users.

PC. A4.2 Mechanical parameters

For SWE Connections, the mechanical parameters related to the performance of the plant are required. For WTG, this may include but is not limited to the drive train characteristics of the **WTG**, the stiffness of the shaft of the **WTG,** Total Inertia constant "H"and/or a multi-mass model of the **WTG** components. Laplace diagrams and associated parameters shall be provided to the **SO** where appropriate.

For Simulation purpose, the Mechanical model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format.

PC. A4.3 Aerodynamic performance

Provide details on the aerodynamic performance of the **Wind Turbine Generator**. This may include but is not limited to variation of power co-efficient with tip speed ratio and **WTG** blade pitch angle, aerodynamic disturbance from **WTG** tower, **WTG** blade pitch control and high and low wind speed performance of the **WTG**. Laplace diagrams and associated parameters shall be provided to the **SO** where appropriate.

For Simulation purpose, the Pitch model of the SWE Connection shall also be required in IEEE or PTI's PSS/E format.

PC. A 4.4 Reactive Power Compensation

Provide details of any additional reactive power compensation devices and control systems employed by the **Controllable SWE**. This shall include **MVAR** capability, the number of stages in the device and the **MVAR** capability switched in each stage and any control or protection systems that influence the performance of the **Controllable SWE** at the **Connection Point**. Laplace diagrams and associated parameters shall be provided to the **SO** where appropriate. Detailed model, if it is a compensator e.g. Static VAR Compensator (SVC) or Static VAR Generator (SVG) or STATCOM or else. For Simulation purpose, the model of the reactive power compensation device shall also be required in IEEE or PTI's PSS/E format.

PC.A 4.5 Control and Protection systems

Provide details of any control or protection systems that affect the performance of the **Controllable SWE** at the **Connection Point.** This shall include any systems or modes of operation that activate during system **Voltage** or **Frequency** excursions including Low **Voltage** Ride Through (LVRT), High **Voltage** Ride Through (HVRT), Low **Frequency** Response and High **Frequency** Response. The transition between Controllable SWE control modes shall also be specified. Laplace diagrams and associated parameters shall also be provided to the SO where appropriate.

PC. A 4.6 Internal network of Controllable SWE

Provide details of the **Controllable SWE's** internal network structure (**Collector Network**) and lay out (by means of a single-line diagram or other description of connections). This shall include but is not limited to a breakdown of how the individual **WTGs** are connected together as well as how they are connected back to the **Controllable SWE** substation. It is required to specify different cables or overhead line types and the individual length of each section of the circuit.

Table PC.A-11 Data Requirement for the Internal Network of Controllable SWE

Type1	Type2	Type3	Extend Table as appropriate
Total length (m)			
Conductor cross section area per core (mm)			
Conductor type (Al, Cu, etc.)			
Type of insulation			
Charging capacitance (µF/km)			
Charging current (Ampere/km)			
Positive sequence resistance(R1 Ohm/km)			
Positive sequence reactance (X1 Ohm/km)			

PC. A4.7 Flicker and Harmonics

Provide details of emission of harmonic or flicker contribution from the Controllable SWE at the **Connection Point** that may affect the performance of the Grid**.** This may include harmonic current injections and phase angles associated with the Controllable SWE. Details of any additional AC filter devices shall also be provided by the Controllable SWE to the **SO.** The flicker and harmonic levels must comply the relevant international standards (IEC and/or IEEE)

PC. A 4.8 Short Circuit Contribution and Power Quality

Provide details of the single-phase to ground, phase-phase and three-phase to ground short circuit contribution from the Controllable SWE at the Connection Point. The Controllable SWE shall provide the SO with the single-phase and three- phase short circuit contribution for rated conditions, i.e. maximum output from the Controllable SWE with all WTGs and any additional devices in the Controllable SWE contributing to the short circuit current. The Controllable SWE shall also provide the single-phase to ground, phase-phase and three-phase to ground short circuit contribution from an individual WTG. Signature plots of the short circuit contribution from an individual WTG shall also be supplied by the Controllable SWE. Minimum short circuit levels at the **Connection Point** would also be provided with the Voltage-Unbalance, Voltage-Dip and Flicker calculated at minimum Short Circuit level.

PC. A5.0 Interconnector/HVDC Data Requirements

Notwithstanding the Interconnectors Technical Code, all information for Interconnector connection applications shall include details of the Transmission System Connection Point and external Transmission System Connection Point. This shall include details listed in PC.A2.1, PC.A2.2 for each Connection Point. The minimum technical, design and operational criteria to be met by Interconnectors are specified in the Connection Conditions.

Interconnector Operating Characteristics and Registered Data

Interconnector Registered Capacity

i. Interconnector Registered Import Capacity for import from the Transmission System (MW);

ii. Interconnector Registered Export Capacity for export to the Transmission System (MW).

Interconnector Registered Capacity shall include transmission power losses for the Interconnector and be considered Registered Data.

(a) **General Details**

i. single line diagram for each converter station;

ii. proposed Transmission connection point;

iii. Control Facility location;

iv. Interconnector Operator details.

(b) **Technology details where applicable**

i. Interconnector technology type (i.e. if AC or DC-Line or Back-to Back DC and, if applicable, current or voltage source technology);

ii. AC/DC network cable or overhead line type & characteristics i.e. length, resistance (R), reactance (X), susceptance(B);

iii. AC/DC rated DC Network Voltage/Pole(kV);

iv. number of Poles and Pole arrangement;

v. Earthing / return path arrangement;

vi. short circuit contribution (three phase to ground, single line to ground, phase to phase);

vii. Interconnector losses(MW/MVar);

- converter station;
- line circuits;
- house load demand;
- losses on de-block at minimum transfer for DC Interconnector;
- total losses at max import /export.

viii. overload capability including details of any limitations i.e. time, temperature;

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

i. total number of AC filter banks;

ii. type of equipment (e.g. fixed or variable);

iii. single line diagram of filter arrangement and connections;

iv. Reactive Power rating for each AC filter bank, capacitor bank, or operating range of each item or reactive compensation equipment (SVC or else), at rated voltage;

v. performance chart (PQ), showing Reactive Power capability of the Interconnector, as a function of Interconnector Registered Capacity transfer.

vi. harmonic and/or flicker contribution from the Interconnector that may affect the performance of the Interconnector at the Connection Point.

vii. Effective Short Circuit Ration (ESR) at the Transmission System Connection Point, compliant to international standards (IEC and/or IEEE)

(d) **Interconnector power electronic converter and control systems**

i. parameters related to the power electronic converters. Interconnector converter characteristics to be represented may include but is not limited by the following; converter firing angle, modulation index, Valve winding voltage, DC Voltage, DC Current as the output variables;

ii. transfer function block diagram representation including parameters of the Interconnector 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, voltage 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, which have not been submitted as part of the above control system data;

vi. transfer block diagram representation including parameters of the Active Power control, DC Voltage control, AC Voltage control and Reactive Power control at converter ends for a voltage source converter for both the rectifier and inverter modes including Voltage set points that would trigger commutation failure, blocking and unblocking of a Pole

vii. transfer block diagram representation including parameters of any control modes that affect the performance of the Interconnector at the Connection Point which have not been submitted as part of the above control system data. Features to be represented shall include but are not limited to the following; start-up sequence, shutdown sequence, Normal operating mode, Voltage Source Converters (VSC) control mode, Island mode and Emergency Power control.

viii. Dynamic model of complete DC Interconnector either from the available model library of PSS/E or a user defined model (.dll file) with complete documentation of inputs, outputs and control features, ensuring successful simulation runs in PSS/E

(e) **Interconnector Transformer**

Table PC.A-12 Interconnector Transformer data requirements

Description	Data
Number of windings	
Vector Group	
Rated current of each winding (Amps)	
Transformer rating (MVA)	
Transformer nominal LV voltage (kV)	
Transformer nominal HV voltage (kV)	
Tapped winding	
Transformer ratio at all transformer taps	
Transformer impedance (Commutation Reactance) at all taps (% on rating MVA)	
Transformer zero sequence impedance at nominal tap (ohm)	
Earthing arrangement including neutral Earthing resistance & reactance	
Core construction (number of limbs, shell or core type)	
Open circuit characteristic	

TRANSMISSION PLANNING CRITERIA & STANDARDS

(TPCS)

Contents

ACRONYMS

ACRONYM	DEFINITION
ΔI	CURRENT DISTURBANCE
ΔU	VOLTAGE DISTURBANCE
ASRAIR	ANNUAL SYSTEM RELIABILITY ASSESSMENT AND IMPROVEMENT REPORT
DISCOS	DISTRIBUTION COMPANIES
FRT	FAULT RIDE THROUGH
HVAC	HIGH VOLTAGE ALTERNATING CURRENT
HVDC	HIGH VOLTAGE DIRECT CURRENT
HVRT	HIGH VOLTAGE RIDE THROUGH
LVRT	LOW VOLTAGE RIDE THROUGH
ms	MILLISECONDS
NEPRA	NATIONAL ELECTRIC POWER REGULATORY AUTHORITY
OHL	OVERHEAD LINE
P	ACTIVE POWER
P.U	PER UNIT
PF	POWER FACTOR
PSS	POWER SYSTEM STABILIZER
Q	REACTIVE POWER
ROCOF	RATE OF CHANGE OF FREQUENCY
SO	SYSTEM OPERATOR
STATCOM	STATIC SYNCHRONOUS COMPENSATOR
SVC	STATIC VAR COMPENSATOR
SWE	SOLAR, WIND AND ENERGY STORAGE GENERATORS
TNO	TRANSMISSION NETWORK OPERATOR
WAMS	WIDE AREA MANAGEMENT/MONITORING SYSTEM
ZVRT	ZERO VOLTAGE RIDE THROUGH

TPCS 1. **INTRODUCTION**

TPCS 1.1. The purpose of this annexure is to provide specific guidelines, criteria and performance standards for developing cost-effective transmission system assets with adequate capacity and redundancy. These assets should enable efficient and reliable system operation while providing open access to Users. Major considerations involve the application of technical reliability criteria, investment requirements, seamless integration with generation and distribution facilities, strategic developments, adoption of new technologies and complying with environmental guidelines**.**

TPCS 1.2. This document i.e. Transmission Planning Criteria & Standards (TPCS) describes;

(a) Planning studies and their respective horizons for developing a reliable National Grid

(b) Normal and contingency conditions

(c) Performance Standards and Criteria

TPCS 2. **PLANNING STUDIES**

TPCS 2.1. **Studies and Horizons**

Table 1 Planning Studies and their Horizons

Sr. No.	Planning Study	Horizon
1.	Global Demand Forecasting	20 years
2.	Spatial Demand Forecasting	10 years
3.	Indicative Generation Capacity Expansion Plan	15 years
4.	Long-term Transmission Plan	15 years
5.	Transmission System Expansion Plan	Minimum 5 years
6.	Investment Plan	Minimum 3 years

TPCS 2.2. **Base Cases**

The following four dispatch scenarios shall be employed to prepare load flow base cases and perform a Grid Impact Study for incorporating a new connection or modification to an existing connection with the Transmission System.

(a) Summer peak and Summer off-peak (High water conditions)

(b) Winter peak and Winter off-peak (Low water conditions)

TPCS 2.3. **System Studies**

SO/TNO employs or cause to employ various analytical techniques to evaluate grid impact after the incorporation of a new connection or modification to an existing connection of a User. The purpose is to ensure compliance with the applicable planning and operation standards for different types of system studies. Accordingly, a scope of work shall be mutually agreed between the SO/TNO and the User before embarking on a specific system study. The scope of a typical Grid Impact Study entails but not limited to the following analyses:

(a) Load flow analysis

(b) Short circuit analysis

(c) Transient stability analysis

In addition, SO/TNO may conduct or cause to conduct further assessments of a new connection or modification to an existing connection, whenever deemed necessary as per the prudent international practices to ensure security and stability of the National Grid is not compromised. These additional studies may include but not limited to the following:

(a) Voltage Stability Studies

(b) Electromagnetic Transient Studies (***including Transient over voltage (TOV)/Dynamic over voltage (DOV), switching surges, LC resonance, Ferro resonance etc.)***

(c) Reliability Studies

(d) Small Signal Stability Analysis

(e) Sub Synchronous Resonance (SSR) Analysis/ Sub Synchronous Torsional Interaction (SSTI) Analysis

(f) Power Quality Studies (for interconnection of RE Plants or loads causing Power Quality issues e.g. harmonics, flicker, voltage dips, and voltage unbalances, etc.)

(g) Fuel Assessment studies

TPCS 3. **NORMAL AND CONTINGENCY CONDITIONS**

TPCS 3.1. **Normal Condition**

TPCS 3.1.1. The normal condition represents the integrated power system with all elements in service and operating within their allowable limits. This is often referred to as (N-0) condition also.

TPCS 3.1.2. The system must be able to supply all firm demand and firm transfers to other areas. All equipment must operate within applicable limits as mentioned in Section 4 of this document “SYSTEM PERFORMANCE REQUIREMENTS” and the system must be stable.

TPCS 3.2. **Contingency Conditions**

The contingency conditions are categorized as: 1) Credible/More Probable Contingencies and 2) Less Probable/ less credible Contingencies

TPCS 3.2.1. **Credible Contingencies**

Credible contingencies include:

(a) Single Contingency (N-1)

(b) Non – Simultaneous Contingencies (N-1-1)

Power System Planning would cater to all credible contingencies.

TPCS 3.2.2. **Single Contingency (N-1)**

Single contingency involves the loss of:

(a) Single transmission element (One Pole of HVDC, a transformer, a cable, OHL circuit, a reactor) with or without fault (three-phase to ground fault with Normal Clearing or single-phase to ground fault with Delayed Clearing)

(b) Largest Operating Unit

The acceptable system impact is summarized as follows:

(a) All equipment must operate within contingency limits following the outage. Automatic system adjustments would respond to achieve contingency limits including, but not limited to governor action of generators, fast response of other controllers e.g. SVC, PSS, WAMS, transformer tap changing and switching of shunt equipment.

(b) No loss of load allowed

The system should be transiently and dynamically stable under single-contingency events. Normal Clearing means clearing of a fault in 5-cycles and Delayed Clearing means clearing of fault in 12.5-cyles owing to a stuck-breaker condition.

Note: -

Exception for N-1 may be given at the Connection Point where a generator of 50MW or below is to be connected with the existing radial transmission line (up to 132kV voltage level), in case of transmission corridor limitations and/or long distance transmission lines etc.

TPCS 3.2.3. **Non – Simultaneous Contingencies (N-1-1)**

This is often referred to as (N-1-1) event. It includes an outage condition (involving single contingency (N-1) either forced or scheduled) followed by system adjustments to operate similar to (N-0) operating conditions. Subsequently, another single forced contingency (N-1-1) occurs. The acceptable system impact under (N-1-1) is as follows:

(a) The system should perform within contingency limits following either outage. Automatic system adjustments would respond to achieve contingency limits including, but not limited to governor action of generators, fast response of other controllers e.g. SVC, PSS, WAMPAC, transformer tap changing, switching of shunts equipment.

(b) Loss of load and loss of generation may be allowed

(c) The system should be transiently and dynamically stable

TPCS 3.2.4. **Less-credible Contingencies**

Less-credible contingencies may include:

(a) Double Contingency (N-2)

(b) Extreme Contingencies (N-M)

(c) Less Probable but High Impact Contingencies

System Operational Planning should address all less credible contingencies.

TPCS 3.2.5. **Double Contingency (N-2)**

Double Contingency involves the loss of a double circuit overhead line (with or without fault) or double circuit towers. Normal Clearing of a double-phase to ground fault shall be assumed for transient stability assessments. The acceptable system impact under (N -2) event is similar to (N–1) event except that loss of load and/or generation is allowed.

TPCS 3.2.6. **Extreme Contingencies (N-M)**

Extreme contingencies may result in instability followed by widespread loss of load and/or generation. Extreme contingency tests should be run to evaluate risks and their associated consequences and to verify that system integrity can be maintained and that it would be possible to attain a new stable state via coordinated load shedding and remedial action schemes (RAS) or special protection schemes (SPS) including islanding. Extreme Contingencies could include:

(a) Outage of critical transmission interfaces with bulk power flows across the regions which may result in extreme situations, i.e., System splitting, System Islanding, and plant tripping, etc.

(b) Outage of multiple units at a Generator.

(c) Other severe events involving delayed fault clearing such as stuck breaker scenario i.e. A single-phase fault followed by circuit breaker failure leading to tripping of multiple elements.

The acceptable system impact allowed is:

(a) Loss of load and loss of generation allowed.

(b) The intact system or islanded system should be transiently and dynamically stable.

However, no voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment is to be permitted.

TPCS 3.2.7. **Less Probable but High Impact Contingencies**

Less probable contingencies involve bus section faults leading to the loss of two or more elements including loss of a substation. The acceptable system impact is as follows:

(a) Loss of load and/or loss of generation allowed

(b) The intact system or islanded system should be transiently and dynamically stable.

(c) No voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment.

Table 2 Normal and Contingency Conditions

Test Conditions	Elements out of Service	Analysis	Acceptable System Conditions
Base Case	All Elements in Service (N-0 Conditions)	Steady State Load Flow	• System within normal operating limits • No loss of load allowed
Single Contingencies (N-1)	Any one of the following; • Largest Operating Unit • Transformer • OHL Circuit • Reactor • Cable • HVDC Monopole	Steady State Load Flow	• System within contingency operating limits immediately after outage. • No loss of load allowed
		Dynamic Analysis	Transiently and dynamically stable
Double Contingencies (N-2)	• Double circuit tower collapse (in hilly areas or plain areas). • Outage of parallel circuits connected to sensitive/strategic Generator like nuclear or a large hydel plant.	Steady State Load Flow	• System within contingency operating limits. • Loss of load allowed.
		Dynamic Analysis	Transiently and dynamically stable
Non-Simultaneous Contingencies (N-1-1)	Single contingency (forced or scheduled)followed by system adjustments and another single forced contingency.	Steady State Load Flow	• System within contingency operating limits • Loss of load allowed
		Dynamic Analysis	Transiently and dynamically stable
Extreme Contingencies (N-M)	• Outage of multiple generating units • System Splitting/Islanding • Loss of Load/Generation. • Delayed fault clearance.	Dynamic Analysis	Avoidance of wide spread loss of load, uncontrolled cascading and system blackouts.
Less Probable High Impact Contingencies	Bus section Loss of two or more elements including loss of substation	Steady State Load Flow	• Loss of load and generation allowed • No voltage collapse, or overloads exceeding the half hour emergency rating of the transmission equipment
		Dynamic Analysis	The intact system or islanded system should be transiently and dynamically stable

TPCS 4. **SYSTEM PERFORMANCE REQUIREMENTS**

The Users will ensure that any of their Apparatus, Equipment, or Plant connected to the Transmission System, shall not cause Power Quality issues such as flicker, harmonics, voltage dips, or voltage unbalance beyond the permissible limits stated in the relevant International Standards (IEC and/or IEEE). Where such limits are exceeded at the Connection Point, the Users shall install appropriate and specific compensation and/or power quality mitigation equipment within their premises/networks. This may include, but not limited to installation of harmonics filter, Static VAR Compensator (SVC) or STATCOM.

System performance assessment studies shall be based on evaluation of many system parameters against their stipulated criteria listed in the subsections below. The studies shall be deemed acceptable if these do not result in any violation of the limits defined in this section for Normal and Contingency conditions.

TPCS 4.1. **Equipment Loading**

TPCS 4.1.1. The following loading criteria shall be observed for load flow studies.

(a) All transmission lines and transformers shall be loaded below their Normal Continuous Maximum Ratings under normal operating conditions (N-0 condition);

(b) All transmission lines and transformers shall be loaded below their Contingency Ratings under contingency conditions (N-1);

(c) Within 20 minutes of the change from the (N-0) state to a Credible Contingency state, and after Spinning Reserve (ten-minute reserve) has been activated, the System shall have the capability to first change generation dispatch and second shed load to reduce any transmission line and transformer loading from the Contingency Rating to Normal Continuous Maximum Ratings.

TPCS 4.1.2. Dynamic ratings for loading limits may be evaluated and applied for specific geographical regions. For instance, loading limits of transmission lines and transformers in the wind corridors or low temperature northern hilly areas may be increased up to 10%. All loading limits shall be determined in accordance with applicable IEC Standards and updated from time to time as new and revised standards become available. In the event that an IEC Standard with necessary scope does not exist, then other applicable standards such as ANSI C57.92, IEEE 738-2012, IEC-287 or other standards of internationally recognized institutions may be used. In the event of a dispute as to which planning and design Standards are to be used, GCRP shall have the final decision.

TPCS 4.1.3. Transmission circuit loading limits shall be based on the following conditions:

(a) Thermal loading limits of the conductors

(b) Maximum ambient temperature i.e. 40degrees Centigrade

(c) Maximum conductor temperature i.e. 90 degrees Centigrade

(d) Minimum clearance to ground at mid-span under maximum load

(e) Allowable overload for 20 minutes

(f) Transient stability and voltage stability limits

(g) Wind velocity

(h) Aging Factor

TPCS 4.1.4. Transformer loading limits shall be based on following conditions:

(a) Maximum loading capacity with forced cooling

(b) Maximum ambient temperature

(c) Allowable overloading for two hours

(d) Summer (April – October) loading; and (November- March) loading

Table 3 Equipment Loading

<table>
<tr><th>Sr. No.</th><th>Equipment</th><th>Loading in N-0 Conditions</th><th>Loading in Contingency Conditions</th></tr>
<tr><td>1.</td><td>Transformers</td><td rowspan="2">100% of rated capacity</td><td>110% of rated capacity</td></tr>
<tr><td>2.</td><td>Transmission Lines</td><td>100% of rated capacity</td></tr>
</table>

TPCS 4.1.5. **Substation Transformer Capacity Adequacy**

TPCS 4.1.5.1. The SO shall submit an "Annual System Reliability Assessment and Improvement Report" (ASRAIR) to NEPRA on or before April 15th of each year for the next year listing the Total Installed Transformer Capacity in MVA, Firm Transformer Installed Capacity, and Estimated Load Demand for the next year for each 765/500 kV, 765/220 kV, 500/220 kV, 500/132 kV and 220/132 kV Substation. For each substation, the ratio of Estimated Peak Substation Demand to Firm Transformer Capacity shall be calculated and reported. If the ratio of Estimated Peak Substation Demand to Firm Substation Capacity is 80% (Single Transformer sub-station) or 100% (more than one Transformer sub-station) then the SO shall identify inadequacies in the transformation capacities and transmission lines that may affect system reliability. Accordingly, respective TNOs, in consultations with SO, shall devise corrective measures and include descriptions of their plans, together with cost and in-service date, to either add additional transformer capacity or to shift load from/to other substations or reconfigure/build transmission lines. If load is shifted to another substation, then the amount of the shifted load will be added to the estimated peak demand for the substation to which the load has been shifted to and will be used to calculate the ratio.

Table 4 ASRAIR Format

<table>
<tr><th colspan="6">SUBSTATION TRANSFORMER CAPACITY ADEQUACY</th></tr>
<tr><th>Substation Name</th><th>Number of Transformers & total name plate Ratings (MVA)</th><th>Transformer Voltage Ratio kV/kV</th><th>Firm Substation Capacity (MVA)</th><th>Estimated Peak Substation Demand (MVA)</th><th>Ratio Of Peak Substation Demand To Firm Transformer Capacity %</th></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

TPCS 4.1.5.2. Firm Substation Capacity MVA is the Total Installed Transformer Capacity less the largest transformer based on its Nameplate MVA rating;

TPCS 4.1.5.3. Transformer MVA loading based on Manufacturer's Nameplate Rating, and IEC standard 60354 Ed 2.0, 1991, Loading Guide for Oil-Immersed Power Transformers; and

TPCS 4.1.5.4. In the case of single transformer sub-station, the Firm Capacity of the sub-station is 80% of Transformer's Nameplate Rating.

TPCS 4.2. **Voltage Limits**

TPCS 4.2.1. **Voltage Limits for HVDC**

Voltage should remain within ± 5% of nominal voltage under normal conditions and ± 10% under contingency conditions. Design of Valves should have enough margins for voltage excursions to avoid Commutation Failure.

TPCS 4.2.2. **Voltage Limits for HVAC system of 765kV**

Voltage should remain within +4.58/-4.84% of nominal voltage under normal and N-1 contingency conditions.

TPCS 4.2.3. **Voltage Limits for HVAC system of 500kV and below**

Voltage should remain within ± 5% of nominal voltage under normal conditions and ± 10% under N-1 contingency conditions. However, voltages at some generating units and/or substations maybe allowed up to +8% of the nominal voltage under normal operating conditions as per network configuration and/or system requirements.

TPCS 4.3. **Voltage Step**

TPCS 4.4. For normal system operation, i.e. with all transmission elements in service, the voltage step resulting from reactive power compensation switching shall not exceed 3.0%. For system outage contingencies, the maximum step change between pre-contingency and post-contingency steady-state voltages shall be no more than 10%.

TPCS 4.5. **Frequency Ranges**

The integrated power system shall be so planned and operated that the system frequency remains within the following limits.

(a) Normal operating range (unlimited time operation) 49.8 Hz to 50.2Hz

(b) Contingency Operating Range (no loss of load) 49.4 Hz to 50.5Hz

TPCS 4.6. **Short Circuit Levels**

Maximum and Minimum Short Circuit current calculation studies should be carried out for three phase and single phase to ground faults. The assumptions for such studies should be based on the IEC 60909 standard, which are given as follows:

(a) For Maximum Short Circuit current calculations, post fault voltage should be 1.1 p.u.

(b) For Minimum Short Circuit current calculations, post fault voltage should be 0.9 p.u.

(c) Planned make and break short circuit currents shall not be greater than the rating of the equipment.

(d) All generating units and transmission elements should be kept in service for maximum short circuit current calculations, whereas minimum generation dispatch should be assumed for minimum short circuit current calculations.

TPCS 4.7. **Dynamic Testing**

TPCS 4.7.1. **Transient stability:**

The strength of the system shall be such as to maintain stability of the system for at least for the following conditions:

(a) Three phase fault cleared in 5 cycles followed by outage of the associated component;

(b) Single phase fault cleared in 12.5 cycles (stuck breaker condition) followed by outage of the associated component; and

(c) In case auto reclosing scheme is implemented, then system should be tested for unsuccessful auto reclosing (with a dead band of 300 ms to 400 ms) followed by single phase fault only.

It shall be assumed that the fault is correctly cleared by primary protection and that automatic line reclosing is in operation where appropriate. System Stability must be maintained and adequately damped without sustained oscillations after the transient period.

TPCS 4.7.2. **Frequency Stability:**

From the perspective of frequency stability, the system shall be able to maintain stability for the:

(a) Loss of largest operating unit or largest power in feed/ loss of importing interconnectors

(b) Loss of large load or out feed/loss of exporting interconnectors

TPCS 4.7.3. **Voltage Recovery Criterion:**

After clearance of fault, the voltage recovery profile should meet the following criterion in order to avoid voltage collapse:

(a) Bus voltages should recover to 0.7pu or should not over shoot to above 1.3pu;

(b) Bus voltages should reach and stay above 0.8 p.u within 1 second from the fault inception;

(c) Bus voltages should reach and stay above 0.9 p.u within 2 second from the fault inception; and

(d) Bus voltages should recover at or below 1.1 p.u within 2 second from the fault inception.

TPCS 4.7.4. **Fault Ride Through:**

Conventional Generators shall stay connected for absolute voltage value in percentage within the shaded areas; depending on the retained voltages of 0% or 50%. The Must-stay-connected areas are the shaded region in the figure below:

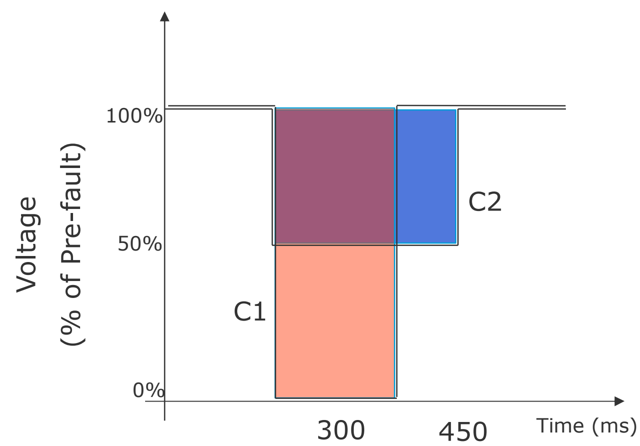


Figure 1 FRT for conventional generators

Table 5FRT duration for conventional generators

Voltage Magnitude	Fault Ride Through duration			
	132 kV	**220 kV**	**500 kV**	**765 kV**
0% retained	300 ms	300 ms	300 ms	300 ms
50% retained	450 ms	450 ms	450 ms	450 ms

TPCS 4.8. **Power Factor**

All demand customers connected with Transmission System, shall ensure a power factor of 0.95 or higher at the connection point. In case of violation, they shall be penalized according to NEPRA defined applicable charges & rules.

TPCS 4.9. **Requirements for HVDC Projects**

TPCS 4.9.1. **Reactive Power Capabilities**

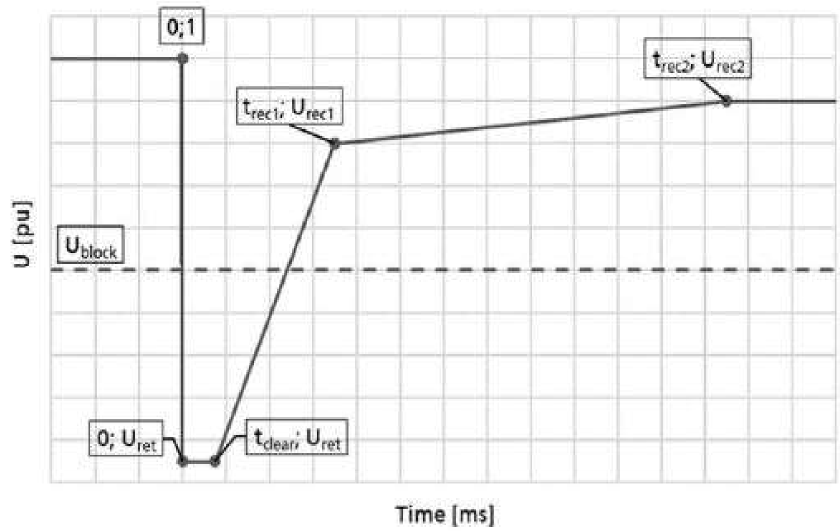
Adequate reactive power compensation equipment (filters) needs to be installed at the HVDC converter stations to ensure efficient and stable operation of the interconnected Transmission System.

TPCS 4.9.2. **SCR Value**

An SCR value of greater than three (3) is recommended at the Connection Point of an HVDC and an AC grid or a hybrid AC/DC grid. Employment of appropriate reactive power devices (synchronous condensers, FACT devices etc.) shall be considered for planning an HVDC to an AC connection.

TPCS 4.9.3. **Fault Ride Through Capability for HVDC**

HVDC Facilities shall be able to ride through faults for a period of 1000 ms, followed by a voltage recovery to 85%. During this time, the facility shall remain connected to the AC network and continue to operate in a stable manner.



Fault-ride-through profile of the DC converter stations. The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference one (1) pu value in per unit before, during, and after a fault. U_{ret} is the retained voltage at the connection point during a fault, t_{clear} is the instant when the fault has been cleared, U_{rec1} and t_{rec1} specify a point of lower limits of voltage recovery following fault clearance. U_{block} is the blocking voltage at the Connection Point under specific network conditions whereby the DC Facilities is allowed to block.

Figure 2 FRT for HVDC Connection (Source: CASA Technical Code)

Table 6 Parameters for FRT capability of an HVDC connection

Voltage Parameters (p.u)		**Time Parameters (sec)**	
U_{ret}	0 - 0.3	t_{clear}	0.14 – 0.25
U_{rec1}	0.25 – 0.85	t_{rec1}	1.5 – 2.5
U_{rec2}	0.85 – 0.9	t_{rec2}	t_{rec1} - 10

TPCS 4.10. **Requirements for Controllable Solar-Wind-Energy (SWE) Projects**

TPCS 4.10.1. **Reactive Power and Voltage Control**

A Controllable SWE must be able to operate in power factor, reactive power or voltage control modes given as follows:

TPCS 4.10.1.1. **Power Factor:**

A Controllable SWE shall manage at the Connection Point the reactive power control to maintain the power factor within the range of 0.90 lagging to 0.95 leading, over the full range of operation, as per dispatch instructions and/or voltage adjustments/requirements within the above range of power factor.

TPCS 4.10.1.2. **Reactive Power:**

A Controllable SWE shall manage at the Connection Point the reactive power control within the set points of Qmin and Qmax as Per Unit of full output of Plant as shown in Figure-3 and Figure-4. The set points of Qmin and Qmax would be as follows:

(a) Qmin = -0.33 P.U. of Full Output

(b) Qmax = + 0.33 P.U. of Full Output

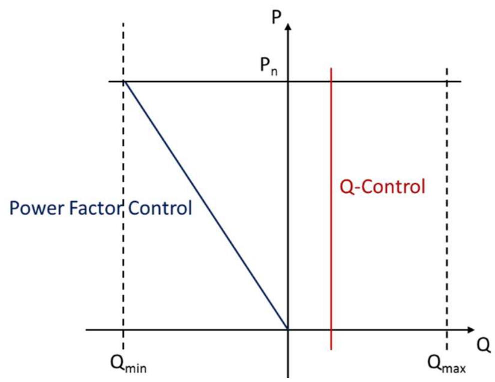


Figure 3 Reactive power control for Wind and Solar Generators

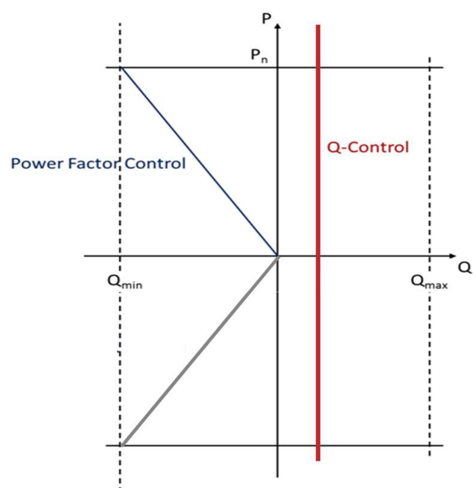


Figure 4 Reactive power control for BESS

TPCS 4.10.1.3. **Voltage Control**

A Controllable SWE must control voltage at Connection Point along a voltage vs. reactive power characteristic as shown in Figure 5. The following parameters are set as:

(a) Voltage offset: ± 5 % under normal operating conditions and ± 10 % during contingency conditions.

(b) Reactive power offset: ± 0.33 PU of Full Output of Plant

(c) Droop (5 % of nominal voltage at max. reactive power)

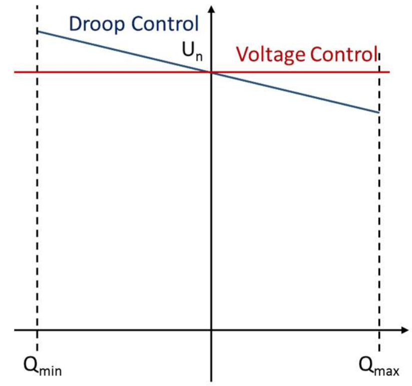


Figure 5 Voltage Control Mode

TPCS 4.10.2. **LVRT and HVRT Requirements:**

TPCS 4.10.2.1. An SWE must stay connected for transient short duration low voltage dips with slow recovery i.e. called Low Voltage Ride through (LVRT), and short duration high voltage swells i.e. called High Voltage Ride Through (HVRT).

TPCS 4.10.2.2. An SWE must have the LVRT/HVRT capability as indicated Figure 6. It is required to stay connected in the voltage envelope below the HVRT curve and above the LVRT curve.

TPCS 4.10.2.3. For LVRT, a controllable SWE must stay connected for;

(a) Zero Voltage I.e. Zero Voltage Ride Through (ZVRT) for the initial duration of 300 ms.

(b) Recovered/Retained Voltage of 30 % for the next duration till 500ms.

(c) Slow voltage recovery up to 0.9 PU in 3 seconds after occurrence of fault.

(d) It may disconnect if the voltage dips below these limits for longer durations as specified in the envelope.

TPCS 4.10.2.4. For HVRT, a controllable SWE must stay connected for;

(a) Voltage swells up to 1.2 PU for the duration of 3 seconds.

(b) Voltage recovers to 1.1 PU in 3 seconds after occurrence of fault

(c) It may disconnect if the voltage swells higher than this limit or for longer duration as specified in the envelope.

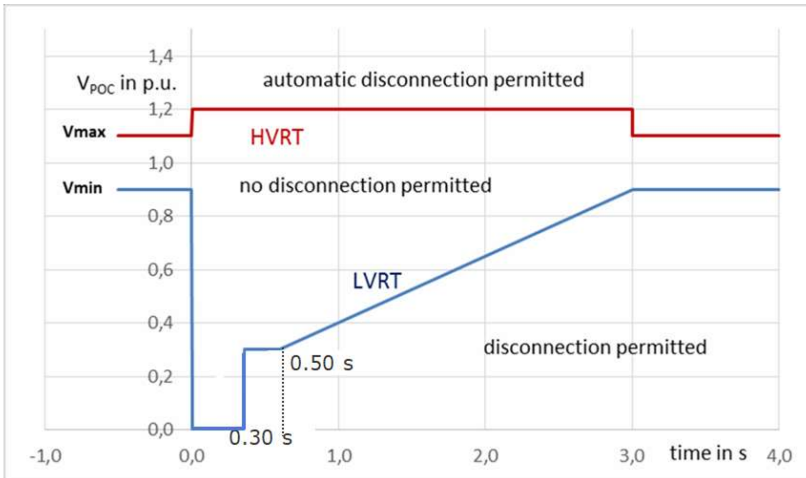


Figure 6 HVRT/LVRT Requirements for SWE Projects

TPCS 4.10.2.5. In order to actively support voltage during low voltage situations (LVRT-situations), a SWE must inject additional reactive current into the grid. Likewise, in order to actively reduce the voltage and help keep the voltage within reasonable limits during high voltage conditions, a SWE must absorb reactive current.

(a) During Transmission System Voltage Dips, the SWE shall provide Active Power in proportion to retained Voltage and provide reactive current to the Transmission System, as set out in Figure 7.

(b) The provision of reactive current shall continue until the Transmission System Voltage recovers to within the normal operational ranges of voltages and frequencies of the Transmission System as specified in the Grid Code or for at least 500ms, whichever is sooner.

(c) The SWE may use all or any available reactive sources, including installed STATCOMS or SVCs, when providing reactive support during Transmission System Fault Disturbances resulting in Voltage Dips.

TPCS 4.10.2.6. The SWE shall provide at least 90% of its maximum Available Active Power or Active Power Set-point, whichever is lesser, as quickly as the technology allows and in any event within 500ms of the Transmission System Voltage recovering to 90% of nominal Voltage, for Fault Disturbances cleared within 140ms. For longer duration Fault Disturbances, but less than 300ms, the SWE shall provide at least 90% of its maximum Available Active Power or Active Power Set-point, whichever is lesser, within 1 second of the Transmission System Voltage recovering to 90% of the nominal Voltage.

TPCS 4.10.2.7. During and after faults, priority shall always be given to the Active Power response as defined in (c). The reactive current response of the SWE shall attempt to control the Voltage back towards the nominal Voltage and should be at least proportional to the Voltage Dip. The reactive current response shall be supplied within the rating of the SWE, with a Rise Time no greater than 100ms and a Settling Time no greater than 300ms. For the avoidance of doubt, the SWE may provide this reactive response directly from individual Generation Units, or other additional dynamic reactive devices on the site, or a combination of both. The characteristics of reactive current support are indicated in Figure 7.

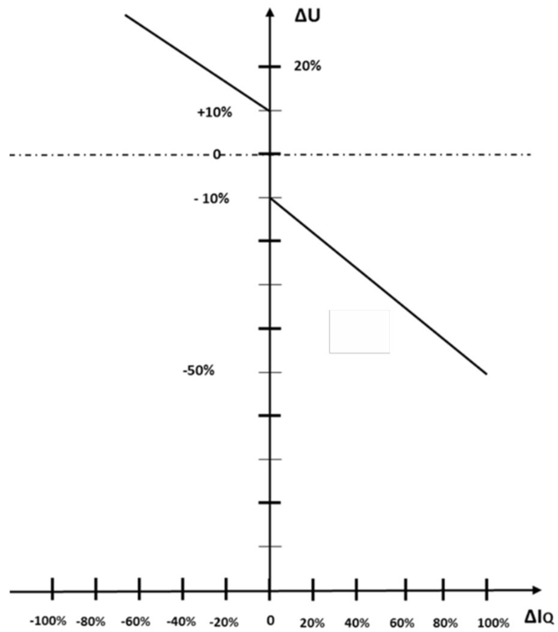


Figure 7 Reactive Current Support Requirements

TPCS 4.10.2.8. According to this figure, a SWE will inject an additional reactive current (ΔIQ in addition to the pre-fault reactive current) into the grid if the difference between post-disturbance and pre-disturbance voltage (ΔU) goes below -10%.

TPCS 4.10.2.9. In the case that ΔU goes above 10%, a high voltage condition is identified, and ΔI will be absorbed in order to stabilize the voltage.

TPCS 4.10.2.10. It is further recommended that ΔI is defined as being in proportion to ΔU (the factor of proportionality is then named "K").

TPCS 4.10.2.11. Besides this, the definition of reactive current support shall include the following:

(a) It applies to both, symmetrical and asymmetrical

(b) Voltage and Current means, deviation of positive sequence voltage and currents post-fault from pre-fault values

(c) The support is required at the generator terminals

(d) The value of K is settable to $0 \leq K \leq 10$

(e) Dynamic performance requirement for this support is 60ms, well below minimum fault clearing times

(f) The accuracy of reactive current injection within the tolerance band of +/-20% of the given value

(g) The limitation of this current would be absolute current value to rated current

(h) The minimum voltage threshold for the applicability of the reactive current support would be 10%, meaning that below a retained voltage of 10%, reactive current injection is not required

TPCS 4.10.2.12. The SWE shall manage active power restoration, after the voltage recovery, at a rate of at least 20% of nominal output power per second, subject to availability of adequate wind speed at site. However active power recovery must not be faster than a rate of 50% of nominal power per second. The active power has to be ramped up to pre-fault level (or maximum available power), or at least to 90% of pre-fault level.

TPCS 4.10.2.13. The SWE must manage reactive power restoration, after voltage recovery, such that post-fault reactive power must not be below pre-fault reactive power with a minimum tolerance of 10% and maximum delay time of 200ms after fault clearance.

TPCS 4.10.2.14. The SWE shall be capable of providing its transient reactive response irrespective of the reactive control mode in which it was operating at the time of the Transmission System Voltage Dip.

TPCS 4.10.2.15. The SWE shall revert to its pre-fault reactive control mode and set point within 500ms of the Transmission System Voltage recovering to its normal operating range as specified in Section 4 of this document.

TPCS 4.10.3. **Power Quality Requirements:**

A SWE shall be compliant with the contents of the Planning Code and Connection Code, in regards to the impact of quality of supply and the compliances. Notwithstanding Planning and Connection Codes, the SWE shall in particular be compliant with the followings:

(a) Power quality parameters, of power output of a SWE shall be governed, for full Term of Energy Purchase Agreement, by latest relevant IEC Standards (IEC61400-21 amended time to time) prevailing at the time of Financial Closing.

(b) Power Quality parameters, for implementation of the previous clause shall be observed at the Point of Interconnection of the grid connected SWE with the National Grid System.

(c) For continuous monitoring of power quality parameters, a SWE shall install and maintain necessary monitoring equipment, at its site.

(d) Failure to maintain the quality of Power within acceptable range shall result in a penalty according to NEPRA defined applicable rates and rules.

CONNECTION CODE

CC 1. INTRODUCTION

The Connection Code (CC) specifies the general terms and conditions, principles, standards, and requirements for accessing and using the Transmission system. First, it describes the procedure for seeking new, or modification of an existing, Connection to the Transmission System. Second, it specifies the performance standards to which the Transmission System is to be maintained and operated by the SO and the TNOs. Third, it specifies the minimum technical design and performance requirements of the User Plant and Apparatus Connected with the Transmission System.

In addition to those specified in the CC, there may be some additional requirements in the individual Connection Agreements between the System Operator and a particular User, defining in greater detail and in more specific terms, the mutual obligations of the SO and the User.

Any reference to a User shall include the Users already Connected with the Transmission System, as well as those, who are seeking a new, or modification of an existing, Connection.

CC 1.1. Objectives

Objectives of this sub-code are:

(a) to provide a set of fair and non-discriminatory basic rules and standards for accessing and using the Transmission System;

(b) to provide the minimum performance standards according to which the SO and TNOs will operate the Transmission System under normal and contingency operating conditions; and

(c) to provide minimum design and performance requirements for Users Plant and Apparatus when Connected with the Transmission System;

CC 1.2. Scope

This Code applies to SO and the following Users:

(a) Transmission Network Operators (TNOs);

- (i) National Grid Company (NGC, currently this is called NTDC)
- (ii) Provincial/Regional Grid Companies (PGCs/RGCs)
- (iii) Special Purpose Transmission License Companies (SPTLs)
- (iv) Distribution Companies (DISCOs)

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

For avoidance of doubt, the above categories of User shall become bound by the Planning Code prior to actually generating, transmitting, distributing or consuming electricity, as the case may be, and references to the various categories (or to the general category) of Users should, therefore, be taken as referring both to a prospective User in that role or to Users actually connected.

CC 2. **CONNECTION PROCESS**

Users will be able to assess opportunities for connecting to, and using, the Transmission System that are most suited to a new, or modification of an existing, Connection(s) through the long-term generation and transmission plans published by the SO or Direct Solicitation by the SO.

CC 2.1. **Principles for Connection**

The provisions specified under this Connection Code are based on, among others, the following principles and conditions:

(a) All Users shall have a fair and equal opportunity to get a new, or modification of an existing, Connection with the Transmission System and benefit from the services provided by the TNO(s) and the SO; and

(b) The SO/TNO(s) shall provide a fair and non-discriminatory treatment to all Users when setting the terms and conditions for new, or modification of an existing, Connection with the Transmission System.

CC 2.2. **Intention Application for Connection/Modification**

CC 2.2.1. Any User seeking a new, or modification of an existing, Connection with the Transmission System shall file an application to SO directly or through relevant TNO along with the requisite documents, by paying the admissible application processing fees, and providing the Project Planning Data as per requirement of Planning Code and the following information:

(a) the type of facilities it intends to establish (generation, distribution, loads, etc.);

(b) magnitude of generation capability and/or Load demand/profile for the facility;

(c) proposed location(s) of the Connection Point(s); and

(d) tentative date by which the connection is sought.

CC 2.2.2. The SO shall check the completeness of the submitted application package and intimate the User within 10 working days whether the User application is acceptable for further processing or not. If the application is found to be unacceptable, the SO in its notification shall clearly state the reasons for its decision, also identifying the deficiencies which when removed will make the application acceptable.

CC 2.2.3. The SO shall intimate User for the duration and tentative scope of Feasibility Study that may be required for the User application assessment.

CC 2.2.4. The required Feasibility Study may be performed by the SO in coordination with relevant TNO in which case the User shall be required to pay the prescribed fee to the SO. Or alternatively, the User can get it performed by any independent consultant from the SO-approved list of consultants as per SOPs.

CC 2.2.5. Based on the results of the Feasibility Study, the SO shall intimate the User the feasible Connection Point(s), availability of transmission capacity along with a budgetary cost estimate to proceed for formal application.

CC 2.3. **Formal Application for a New, or Modification of an Existing Connection**

CC 2.3.1. The User shall submit the formal application to SO for evaluation of the SO and the relevant TNO. The formal application package shall include the following:

(a) Project Planning Data as per requirement of the Planning Code;

(b) preliminary design of the User Facility that the applicant intends to install;

(c) expected Connection date;

(d) information required as per attached annexures;

(e) any other information as deemed necessary by the SO and/or the TNO; and

(f) application processing fees, if Any.

CC 2.3.2. The SO shall check the completeness and intimate the User regarding the timelines for the assessment of formal application to the User.

CC 2.3.3. The SO will carry out Grid Impact Studies and share it with the relevant TNO to conduct the necessary Facility Assessment Studies required for the Connection of the User Facility with the Transmission System. Results of Facility Assessment Studies shall be shared with the SO for validation (or revision, if required) of Grid Impact Studies.SO may allow User to get Grid Impact Studies performed by any independent consultant from the SO-approved list of consultants *as per SOPs.*

CC 2.3.4. The SO shall give “Offer to Connect” to the applicant on the basis of above studies. It shall include the following.

(a) detailed Connection Configuration

(b) firm Connection Date;

(c) proposed transmission interconnection and reinforcement facilities, if any;

(d) detailed cost estimate for item (c).

CC 2.3.5. On receipt of an "Offer to Connect" to the Transmission System, the User shall bear the costs related to development of all facilities from User Site up to and at the identified Connection Point. In addition, Generators and Transmission-Connected BPCs shall bear the additional costs related to the reinforcement of the Transmission System beyond the identified Connection Point on pro rata basis, as calculated by SO/relevant TNO.

CC 2.3.6. If a new Generator/ Transmission-Connected BPC is utilizing an ongoing/already completed reinforcement whose cost has already been apportioned among other Users, the new User shall also bear the pro rata cost of such reinforcement.

CC 2.3.7. The User shall inform the SO within three (3) months of receiving the “Offer to Connect” of its acceptance along with proof of payment of the costs specified in the SO’s Offer. In case the User fails to inform the SO of its acceptance along with payment proof within the stipulated period, the “Offer to Connect” shall lapse automatically.

CC 2.4. **Connection Agreements**

The following minimum information shall be supplied by the User to the SO prior to signing of the Connection Agreement and will form the basis for setting the terms and condition of the Connection Agreement:

(a) Registered Planning Data as specified in the Planning Code and Data Registration Code with estimated values being confirmed or replaced with validated actual values and updated Forecast Data such as Load Demand pursuant to the Planning Code;

(b) details of the technical design of switchyard, protection, metering and telecommunication facilities at the Connection Point;

(c) copies of all safety rules and local safety instructions applicable at the User's Sites;

(d) information regarding Site Responsibility Schedules;

(e) an operation diagram for all HV apparatus at interface voltage on the User side of the Connection Point;

(f) unique proposed name of the User Site;

(g) written confirmation that the Safety Coordinators acting on behalf of the User are authorized and competent pursuant to the requirements of OC 13, and relevant sections of this CC;

(h) a list of manager(s) who have been duly authorized to sign Site Responsibility Schedules on behalf of the User;

(i) site common drawings; and

(j) a list of the telephone numbers for the User's facsimile machines and other recordable communication media acceptable to System Operator.

CC 2.5. The Demand User with aggregate capacity of 30MW or less applying for connection according to PC 4.4.6, relevant TNO shall perform all activities mentioned in CC 2.2 to CC 2.4 in coordination with SO.

CC 2.6. The Users shall be responsible for complying with any other applicable law or regulation of any other entity such as those of the Environmental Protection Agency (EPA).

CC 2.7. Acceptance of the "Offer to Connect" shall be followed by execution of the Connection Agreement or an amended Connection Agreement, as the case may be, between the User, which will render the respective User Facility as Committed User Facility and will bind the parties in accordance with the relevant terms and conditions.

CC 2.8. The User shall be bound to comply with all the provisions of the Grid Code (as amended from time to time) as well as the Connection Agreement before Connection and also after Connection for the entire validity period of the Connection. Failure to comply with any provision(s) laid down in the Grid Code or the Connection Agreement shall be a sufficient cause for Disconnecting its facility from the Transmission System as per OC 6 and liable under NEPRA (Fine) Rules.

CC 2.9. **Maintenance and Replacement of Interconnecting Facilities due to Aging/damage**

The User, who owns the assets at the Connection Site shall be liable for maintenance of the equipment. All the costs incurred in this respect shall be borne by the owner of the assets. The SO shall approve the Outage Plan for the maintenance to be performed in line with OC. The replacement of equipment due to aging shall be the responsibility of the User, who owns the assets.

CC 3. **NETWORK BOUNDARIES**

The network bifurcation point between Users shall be clearly defined in the Connection Agreement else it would be tee-clamp of dropper from gantry span to switch yard equipment.

CC 4. **TECHNICAL STANDARDS**

All User Plant and Apparatus at the Connection Point shall comply with the Grid Code, applicable standards and specifications of the NGC to meet functional requirements of SO.

CC 5. **SYSTEM PERFORMANCE PARAMETERS**

CC 5.1. The SO shall ensure that the Transmission System complies with the technical, design and operational criteria, standards, and limits specified in this CC.

CC 5.2. The Users shall ensure that their facilities are designed and operated within the limits and according to the performance standards specified in this CC and their respective Connection Agreements.

CC 5.3. **Transmission System Voltages**

CC 5.3.1. Under normal and N-1 contingency conditions, Transmission System voltage shall be maintained within the bandwidth as mentioned below.

Table CC-1. Transmission System Voltages

Voltage Level (kV)	**Normal Condition**		**N-1 Condition**	
	Max kV	**Min kV**	**Max kV**	**Min kV**
765	800	728	800	713
500	540	475	550	450
220	238	209	245	198
132	142	125	145	119
66	70	63	72	59

CC 5.3.2. Some Transmission System disturbances (e.g. earth faults, lightning strikes) may result in short-term Voltage deviations outside the above ranges.

CC 5.4. The negative phase-sequence component of Transmission System Voltage will not exceed 1% under normal operating conditions.

CC 5.5. The Transmission System shall be designed and operated to maintain the Short-Circuit Current as identified by the SO at different points in the System through periodic studies.

CC 5.6. **Frequency Withstand Capabilities**

The Power System Frequency is nominally 50 Hz but could rise to 53.0 Hz or fall to 47.0 Hz in exceptional circumstances. Design of User Plant and Apparatus shall ensure stable operation of their facility within that range in accordance with the following:

Table CC-2.System Frequency Ranges

	Frequency	Requirement
Below Nominal	47.0 Hz - 47.5 Hz	Operation for a period of at least 20 seconds is required each time the Frequency is below 47.5 Hz
	47.5 Hz – 48.0 Hz	Operation for a period of at least 15 minutes is required each time the Frequency is within the range 47.5 - 48.0 Hz
	48.0 Hz - 49.0 Hz	Operation for a period of at least 90 minutes is required each time the Frequency is within the range 48.0 - 49.0 Hz
Nominal	49.0 Hz – 51.0 Hz	Continuous operation
Above Nominal	51.0 Hz - 51.5 Hz	Operation for a period of at least 90 minutes is required each time the Frequency is within the range 51.0 – 51.5 Hz
	51.5 Hz – 52 Hz	Operation for a period of at least 15 minutes is required each time the Frequency is above 51.5 Hz
	52.0 Hz – 53.0 Hz	Operation for a period of at least 20 Seconds is required each time the Frequency is above 52.0 Hz

For the avoidance of doubt, disconnection, by frequency or speed-based relays is not permitted within the frequency range 47.0 Hz to 53 Hz before lapse of time period given in Table CC-2 unless as specified by SO.

CC 6. **SPECIFIC TECHNICAL PARAMETERS**

CC 6.1. To facilitate secure and stable operation of the Transmission System for the benefit of all Users, it is necessary that Users' Plant and Apparatus is designed to be capable of sustained operation within a range of Transmission System conditions.

CC 6.2. **All Users**

CC 6.2.1. **Earthing**

CC 6.2.1.1. The Earthing of all Users Plant and Apparatus and provision of an Earthing system shall as a minimum requirement be in accordance with the recommendations contained in the "Guide for Safety in Alternating Substations Grounding", ANSI/IEEE No. 80.

CC 6.2.1.2. For Connections to the Grid at all nominal system voltages, the Grid is solidly earthed with Earth Fault Factor below 1.4.

CC 6.2.1.3. Each User's earth disconnects must be earthed directly to the main station earth grid.

CC 6.2.1.4. Each User's Earthing system shall be bonded to the Transmission Station earth grid so that both the Earthing systems are effectively integrated.

CC 6.2.2. **Lightning Protection**

Each User shall adopt best industry practices for lightning protection of their Plant and Apparatus.

CC 6.2.3. **Design**

CC 6.2.3.1. User Plant and Apparatus shall be designed with the following minimum capabilities (at the applicable Voltage levels), as specified in Table CC3. In case some parameters are not available in this table, values/standards recommended by the SO shall be followed.

Table CC-3. Reference minimum withstand Voltages AC

Parameter (Minimum) (kV)	**66 kV**	**132kV**	**220kV**	**500kV**	**765kV**
Insulation level - Lightning impulse - Switching impulse - Power frequency (1min)	 325 140	 650 - 275	 1050 - 460	 1550 1300 620	 2100 1550 830

CC 6.2.3.2. User Plant and Apparatus at the Connection Point shall be designed taking account of the Short Circuit Current levels identified in Grid Impact Studies and applicable SO standards. The User shall determine, what safety margins, if any, to apply when selecting the User's Plant and Apparatus.

CC 6.2.4. **Transformers**

CC 6.2.4.1. All transformers, except the Generator Transformer, connected with the Transmission System shall be equipped with an on-load tap-changer (OLTC) facility having ±10% voltage regulation range. The requirement for an OLTC on Generator Transformer shall be established through Grid Impact Studies. The OLTC mechanism shall possess automatic, manual and blocking functions.

CC 6.2.4.2. Generator Transformer windings shall be connected in star-delta (Y-d) configuration. The star or neutral point of the star configuration shall be brought out for system grounding.

CC 6.2.4.3. All transformers, except the Generator Transformer, may be connected either:

(a) In delta-star (D-y) configuration. The star or neutral point of the star configuration shall be brought out for system grounding; or

(b) In star-star (Y-y) configuration with a tertiary winding in delta configuration.

CC 6.2.5. **Synchronizing Facility**

All Users shall provide Synchronization facility and associated controls at circuit breaker(s) as required by SO.

CC 6.2.6. **Metering Systems**

Users shall provide Metering Systems in accordance with the provisions of the Metering Code.

CC 6.3. **Generators**

CC 6.3.1. Each Generator shall, as a minimum, have the following capabilities;

(a) deliver Active and Reactive Power at the Connection Point according to its registered Capability Curve as provided in the relevant Connection Agreement.

(b) remain Synchronized with the Transmission System during rate of change of Frequency (ROCOF) in the system. The detailed settings of ROCOF are elaborated in the PCC3.3. For the avoidance of doubt, this requirement relates to the capabilities of Generating Units only and does not impose the need for ROCOF protection nor does it impose a specific setting for any anti-islanding or loss-of-mains protection relays.

(c) remain Synchronized during and following any Fault disturbance anywhere in the Transmission System.

(d) remain Synchronized with the Transmission System during a negative phase sequence load unbalance of 5% of positive sequence component in accordance with IEC 60034-1.

(e) The Short Circuit Ratio (SCR) of each Generating Unit shall be in line with the system studies as follows

(i) Short Circuit Ratio of each Steam Turbine Generating Unit (e.g. coal, natural gas, biomass, nuclear), Wind Farms, Gas Turbine Units etc. shall be more than 0.5; and

(ii) Short Circuit Ratio for Hydroelectric Generators shall be more than 1.1.

(f) Generator Terminal Voltage variation shall be maintained within ±5% at rated power output (MW)with power factor range of 0.8 lagging to 0.9 leading or otherwise power factor specified in the Grid Impact Studies on a case to case basis. Non-synchronous Generators shall comply above requirement as per system studies.

(g) Minimum Load, Ramp up/down capability of Generating unit shall be as per table-CC4 and table-CC5 below;

Table CC-4. Reference min. Load ceiling and Ramp rate for Thermal Generators.

Sr. #	Thermal Generation Technologies	Minimum Load ceiling (% of Registered Capacity)	Ramp rate (% of Registered Capacity/min)
1.	CFPP (Hard coal)	25%	1.5-4%
2.	CFPP (Lignite)	50%	1-2%
3.	CCGT	20%	2-4%
4.	OCGT	20%	8-12%
5.	ICE	20% per unit	100%
6.	ST (RFO/HSD/Gas)	20%	2-5%

Table CC-5. Reference minimum Load ceiling and Ramp rate for Renewable Generators.

Sr. #	Generation Technologies	Minimum Load ceiling (% of Registered Capacity Subject to availability)	Ramp rate (% of Registered Capacity/min Subject to availability)
1.	PV & CSP	0-100%	10%
2.	Wind	0-100%	10%

Any specific requirements for plant(s) established during study stage shall supersede above reference values.

(h) Forbidden Zones within the range between normal Minimum Load plus 5% and Registered Capacity less 10%, not more than 1 specified zone not greater than 10% of Registered Capacity.

(i) Block Loading not greater than 10% of Registered Capacity.

(j) Time to off-load before going into longer standby conditions remain in a hot condition for at least 12 hours and remain in a warm condition for at least 60 hours.

(k) Time to Synchronize from receiving of a dispatch instruction: hot: not greater than 8 hours; warm: not greater than 150 hours; cold: greater than 150 hours:

(i) Time from Synchronizing to Minimum Load: hot: not greater than 40 minutes; warm: not greater than 90 minutes; cold: not greater than 180 minutes

(ii) Time to de-load from Minimum Load to De-Synchronizing: not greater than 40 minutes.

(l) The SO may require Generating Units with Registered Capacity greater than or equal to 50 MW for thermal Generators and 20 MW for reservoir/pond based hydro Generator to have AGC provision at all loads between AGC minimum load and AGC maximum load.

(m) Remain Synchronized with the Transmission System and continue to operate stably during and following any Fault disturbance anywhere on the Transmission System which could result in Voltage Dips at the Connection Point. The voltage-against-time profile specifies the required capability as a function of voltage and Fault Ride-Through time at the Connection Point before, during and after the Fault disturbance. That capability shall be in accordance with the voltage-against-time profile as specified in Transmission Planning Criteria and Standards of Grid Code.

(n) Capable of disconnecting automatically from the Transmission System in order to help preserve system security or to prevent damage to the Generating Unit. The SO shall approve the criteria for detecting loss of angular stability or loss of control and angular stability under fault conditions.

(o) The maximum admissible Active Power reduction from Registered Capacity with falling frequency shall be no greater than:

(i) Steady State domain: 2% of the Registered Capacity at 50 Hz, per 1 Hz frequency drop, below 49.5 Hz to 49 Hz; and

(ii) Transient domain: 2% of the Registered Capacity at 50 Hz, per 1 Hz frequency drop, below 49 Hz.

and subject to the ambient condition correction curves as provided by each individual Generating Unit as well as other relevant technical factors as agreed between the SO and the Generator.
For Generating Units using gas as a fuel source at the time of the low frequency Event, the standard ambient conditions for the measurement of admissible Active Power reduction will be 25°C, 70 % relative humidity and 1013 hPa.

For all Generating Units where a Secondary fuel is available:

(p) The Generating Unit must be capable of starting up on Secondary Fuel. The Generating Unit must be capable of carrying out an online fuel changeover from Primary Fuel to Secondary Fuel at Primary Fuel Switchover Output in minimum time as agreed with the SO. When operating on Secondary Fuel, the Generating Unit must be capable of operating on Secondary Fuel nearest to Primary Fuel Registered Capacity. The Generating Unit must also be capable of carrying out an online fuel changeover from Secondary Fuel to Primary Fuel at Secondary Fuel Switchover Output.

(q) The Generating Unit must have sufficient stock of Primary Fuel and Secondary Fuel equivalent to thirty (30) days or more of continuous running at Primary Fuel Registered Capacity. A minimum of five days of running at Primary Fuel Registered Capacity on Secondary Fuel must be stored at the Generator site. The remainder of the Secondary Fuel stock requirement may be stored at an Off-Site Storage Location.

(r) Users shall install Generating Unit governors that comply with OC 5. Users shall not change frequency or load related control settings of Unit governors without prior written approval of SO. Generating Units shall be capable of setting droop between 2% and 12%. The default droop setting shall be 4%.

CC 6.3.2. Where start-up time of Generating Units exceeds thirty (30) minutes, they shall be designed to have the capability, where supply from the Transmission System is lost, to reduce output to match house load and sustain operation (i.e. tripping to Auxiliaries).

(a) In case of disconnection of the Generating Unit from the Transmission System, the Generating Unit shall be capable of quick re-Synchronization as per requirement of the SO.

(b) Where start-up time of a Generating Unit exceeds fifteen (15) minutes, it shall be designed to have the capability, if supply from the Transmission System is lost, to reduce its output to match house load and sustain such operation (i.e. tripping to Auxiliaries). Generating Units must be designed to trip to house load from any operating point in its Reactive Power

Capability Curve. In this case, the identification of house load operation must not be based solely on the switchgear position signals.

(c) Generating Units shall be capable of continuing its operation for four (04) hours following tripping to house-load.

CC 6.3.3. Control Synchronizing shall be provided by Generators at all circuit breakers or as identified by the SO, depending on the Plant configuration under the following conditions:

(a) Transmission System Frequency within the limits 47.0 to 53.0 Hz; and

(b) Transmission System Voltage within the limits as specified in CC 5.3.

CC 6.3.4. Each Generating Unit shall be designed, where practicable, to mitigate the risk of common mode failure with other Generating Units. Auxiliary supplies provided shall be in accordance with good industry practice and shall be approved by the SO.

CC 6.3.5. **Reactive Power capability**

Notwithstanding the limitations for solar, wind and ESUs (in discharging mode), each Generating Unit shall have the following Reactive Power capability as measured at Connection Point with the Transmission System:

Table CC-6. Voltage ranges and Reactive Power at Connection Point

Voltage Range	Connected at	From Minimum Load to Rated Power
0.90pu ≤ **V** ≤ 1.10pu	132kV, 220kV, 500kV	Reactive Power output shall fully correspond to the Capability Curve of the respective Generator.
0.90pu ≤ **V** ≤ 1.05pu	765kV	

The Generating Unit shall be able to operate at any point within its Generator Capability Curve in appropriate timescale to target values.

CC 6.3.6. **Generator Control Systems**

CC 6.3.6.1. Generating Unit shall be capable of contributing to Primary Frequency Control, and Secondary Frequency Control where applicable (AGC and LFC).

CC 6.3.6.2. Generating Unit shall be capable of regulating voltage within the specified range at the Connection Point.

CC 6.3.6.3. Generating Unit shall be capable of providing adequate damping to the power oscillations for maintaining the steady-state and dynamic stability of the National Grid.

CC 6.3.7. **Turbine Control System**

CC 6.3.7.1. Generating Unit shall be fitted with a fast acting Turbine Controller. The turbine speed control principle shall be in such a way that the Generating Unit output shall vary with rotational speed according to a proportional droop characteristic (Primary Control) and the frequency of Generating Unit.

CC 6.3.7.2. Superimposed Load Control loops shall have no negative impact on the steady state and transient performance of the Turbine Speed Control.

CC 6.3.7.3. The turbine shall be capable of operating at speeds corresponding to the frequency ranges mentioned in Table CC2.

CC 6.3.7.4. Turbine Controller shall provide sufficient damping for both isolated and interconnected operation modes. The damping coefficient of the Turbine Speed Control shall be above 0.25 for speed droop settings between 2 and 12%, under all operation conditions.

CC 6.3.7.5. Turbine Controller shall have no negative damping on generator oscillations for frequencies below two (2) Hz.

CC 6.3.7.6. The Turbine Speed Controller and any other superimposed control loop (Load Control, gas turbine temperature limiting control, etc.) shall not compromise the Primary Control response requirements.

CC 6.3.7.7. The normalized primary response characteristic as defined by the primary response performance Index shall be maintained under all operating conditions. Consequently, in the event that a Generating Unit becomes isolated from the system but is still supplying Demand, the Generating Unit must be able to provide Primary Control according to the Primary Response Performance Index.

CC 6.3.8. **Automatic Voltage Regulator**

CC 6.3.8.1. A continuous Automatic Voltage Regulator (AVR) acting on the excitation system is required to provide constant terminal voltage of the Generating Unit without instability over the entire operating range of the Generating Unit. Control performance of the voltage control loop shall be such that under isolated operating conditions the damping coefficient shall be above 0.25 for the entire operating range. The Automatic Voltage Regulator (AVR) shall have no negative impact on generator oscillation damping.

CC 6.3.8.2. The specific requirements for automatic excitation control facilities, including Power System Stabilizers (PSS) where these are necessary for system reasons, shall be specified in the Connection Agreement. Operation of such control facilities shall be in accordance with the Operation Code and Scheduling and Despatch Code.

CC 6.4. **HVDC System and Convertor Station**

CC 6.4.1. High-Voltage Direct Current (HVDC) systems and convertors which includes embedded HVDC, Interconnector, back to back, isolated/linked Power Park modules when connected with Transmission System shall be provided with the following minimum capabilities in addition to other applicable sections of CC and standards; These requirements, which shall further be detailed in the relevant agreements as otherwise applicable, includes Line Commutated Convertors and Voltage Source Convertor HVDC.

CC 6.4.2. **HVDC Configurations**

HVDC system includes following configurations;

(a) Bipolar with ground return or dedicated metallic return.

(b) Monopolar with ground return, metallic return on other pole conductor or dedicated metallic return

(c) Symmetric monopole

(d) Rigid bipole

(e) Operation with one or more converters out of service in a pole (for multiterminal HVDC system)

CC 6.4.3. **Control Modes**

This section includes HVDC control modes;

CC 6.4.3.1. **Bipole Power Control Mode**

In a bipolar system, the most usual mode of control is bipole power control. In this mode the power order is divided between the two poles in inverse proportion to the DC operating voltage of the pole.

CC 6.4.3.2. **Pole Power Control Mode**

CC 6.4.3.2.1. A bipolar HVDC system shall be capable of operation with one or both poles in individual power control mode. The Power Order shall be settable in each of the two poles independently.

CC 6.4.3.2.2. In a multi-terminal system, the power order of one of the converter operating in inverter mode shall control voltage while the other converter shall operate in voltage control. The power order refers to the power transfer at the rectifier terminal. The power transfer voltage setting inverter terminal will transmit any power not transmitted by the inverter terminal in voltage control.

CC 6.4.3.3. **Pole Individual Current Control Mode**

A bipolar HVDC system shall be capable of operation with one or both poles in constant current control. The current shall be settable in each of the two poles independently**.**

CC 6.4.3.4. **Pole Reduced Voltage Mode**

Each pole of the HVDC system shall be capable of operation with full or reduced voltage at the reduced voltage levels specified for the project. The reduced voltage mode shall be initiated or reset in each pole separately and the operating dc voltage in each pole shall be independently settable. Reduced voltage mode is a sub-mode and shall be available in any of the other operating modes described in this section**.**

CC 6.4.3.5. **Round Power Mode**

If specified by the SO, a bipolar HVDC system shall be capable of operation with different power direction in each of the two poles independently. In a multi-terminal system the power direction and the power order of each converter shall be independently settable.

CC 6.4.3.6. **Reactive Power Control Mode**

HVDC converter station shall be capable of operating in one or more of the following three control modes:

CC 6.4.3.6.1. **Voltage Control Mode (U-control)**

Each HVDC converter station shall be capable of contributing to voltage control at the connection point utilizing its capabilities, in accordance with the following control characteristics:

(a) A set-point voltage at the connection point shall be specified to cover a specific operation range, either continuously or in steps.

(b) The voltage control may be operated with or without a dead band around the set-point selectable in a range from zero to +/– 5 % of reference 1 pu network voltage.

(c) voltage control mode shall include the capability to change reactive power output based on a combination of a modified set-point voltage and an additional instructed reactive power component. The slope shall be specified by a range and step as approved by the SO.

CC 6.4.3.6.2. **Reactive power exchange mode (Q-control)**

SO shall specify in relevant agreement a reactive power range, dead band and reference value of Q control in MVAR or in % of maximum reactive power, as well as its associated accuracy at the connection point.

CC 6.4.3.6.3. **Power factor control mode**

HVDC converter station shall be capable of controlling the power factor to a target value mention in CC 8.1 at the connection point.

CC 6.4.4. **Rate-of-change-of-frequency**

HVDC system shall remain connected to the Transmission System during rate of change of frequency (ROCOF) in the System up to and including 2.5 Hz per second (ROCOF averaged over the previous 1 second).

CC 6.4.5. **Frequency Control**

HVDC system shall be equipped with an independent control mode to modulate the active power output of the HVDC converter station to maintain stable system frequencies. Operating principle, the associated performance parameters and the activation criteria of the Frequency Control shall be as specified by the SO.

CC 6.4.6. **Frequency Sensitive Mode (FSM, LFSM-O and LFSM-U)**

Frequency sensitive mode shall be operable within specified ranges with two modes i.e., limited frequency sensitive mode over frequency and limited frequency sensitive mode under frequency.

CC 6.4.7. **Active Power Controllability (Control Range and Ramp Rate);**

HVDC system shall be capable of and equipped to:

(a) adjust the transmitted active power up to its maximum HVDC active power transmission capacity in each direction;

(b) modify the transmitted active power infeed in case of disturbances into one or more of the AC networks to which it is connected; and

(c) control functions enabling the SO to modify the transmitted active power for the purpose of balancing.

(d) ramp rate or active power transfer increase and decrease shall be adjustable within the technical capabilities of the HVDC system in from a minimum of 1 MW per minute to 1000MW per minute with a setting granularity of 1 MW per min.

CC 6.4.8. **Maximum Loss of Active Power**

CC 6.4.8.1. HVDC system shall be configured in such a way that its reduction of active power injection in a synchronous area shall be limited to a value specified by the SO for their respective load frequency control area, based on the HVDC system's impact on the power system where applicable.

CC 6.4.8.2. Where an HVDC system connects two or more control areas, the SO shall consult with other control area SO in order to set a coordinated value of the maximum loss of active power injection as referred above, taking into account common mode failures.

CC 6.4.8.3. The AC filter design, reactive power supply and absorption design, automatic filter switching and reactive power control design of the HVDC System Owner are subject to the approval of the System Operator.

CC 6.4.9. **Withstand Capability**

The HVDC facilities shall be capable to remain connected to the Grid for a minimum duration of 1000 millisecond without damage in response to external fault.

CC 6.4.10. **Capable of Riding Through Fault**

The HVDC converter station shall be capable of staying connected to the network and continuing stable operation after the power system has recovered following fault clearance. The SO shall consider the pre- fault and post-fault conditions regarding:

(a) pre-fault minimum short circuit capacity at each connection point expressed in MVA

(b) pre-fault operating point of the HVDC converter station expressed as active power output and reactive power output at the connection point and voltage at the connection point; and

(c) Post-fault minimum short circuit capacity at each connection point expressed in MVA.

(d) Alternatively, generic values for the above conditions derived from typical cases.

CC 6.4.11. **Fault Conditions Specified as A Voltage-Time Profile**

(a) The HVDC converter station shall be capable of staying connected to the network and continue stable operation when the actual course of the phase-to-phase voltages on the network voltage level at the connection point during a symmetrical fault, given the pre-fault and post-fault conditions provided for in, remain above the lower limit set out in CC. Annex-2, unless the protection scheme for internal faults requires the disconnection of the HVDC converter station from the network. The protection schemes and settings for internal faults shall be designed not to jeopardize fault-ride-through performance.

(b) The SO may specify voltages (Ublock) at the connection points under specific network conditions whereby the HVDC system is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a time frame that shall be as short as technically feasible and which shall be agreed between the SO and the User.

(c) The SO shall specify fault-ride-through capabilities in case of asymmetrical faults.

CC 6.4.11.1. **Post Fault Active Power Recovery**

The SO shall specify the magnitude and time profile of active power recovery that the HVDC system shall be capable of providing, in accordance with section CC 6.4.4.

CC 6.4.11.2. **Fast Recovery from DC Faults**

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 coordination and agreements on protection schemes and settings.

CC 6.4.12. **Requirements for Control**

CC 6.4.12.1. **Converter Synchronization/De- synchronization**

Unless otherwise instructed by the SO, during the energization or synchronization of an HVDC converter station to the AC network or during the connection of an energized HVDC converter station to an HVDC system, the HVDC converter station shall have the capability to limit any voltage changes to a steady-state level specified by SO. The level specified shall not exceed 5 per cent (5%) of the pre-synchronization voltage. The SO, shall specify the maximum magnitude, duration and measurement window of the voltage transients.

CC 6.4.12.2. **Interaction between HVDC systems or other Plants and Apparatus**

The SO may specify transient levels of performance associated with events for the individual HVDC system or collectively across commonly impacted HVDC systems. This specification may be provided to protect the integrity equipment and that of grid users in a manner consistent with grid code.

CC 6.4.12.3. **Power Oscillation Damping Capability**

The HVDC system shall be capable of contributing to the damping of power oscillations in connected AC networks. The control system of the HVDC system shall not reduce the damping of power oscillations. The SO shall specify a frequency range of oscillations that the control scheme shall positively damp and the network conditions when this occurs on the basis of dynamic stability assessment studies.

CC 6.4.12.4. **Sub Synchronous Torsional Interaction Damping Capability**

With regard to sub synchronous torsional interaction (SSTI) damping control, the HVDC system shall be capable of contributing to electrical damping of torsional frequencies.

CC 6.4.13. **Network Characteristics**

The pre-fault and post-fault conditions for the calculation of at least the minimum and maximum range of short circuit power and other network characteristics at the connection points for stable HVDC system operation shall be declared by User in intention application.

CC 6.5. **HVDC Supplementary Controls**

HVDC systems shall be equipped with the following supplementary control functions and the necessary input hardware and interface points so that the functions can be readily implemented at any time:

(a) Runback and Run-up controls

(b) Fast power transfer between poles at single pole block and during single pole dc line faults and fault clearing

(c) Frequency Limiter Control

(d) Frequency control of the AC system at any one converter station if the other converter station(s) of the HVDC system are within a different asynchronous area

(e) Power oscillation damping controls

(f) Sub-synchronous oscillation damping controls

CC 7. **PROTECTION AND CONTROL SYSTEM**

CC 7.1. Every User shall design protection and control system of its facility ensuring minimal disturbance to the Transmission System operation in accordance with the Protection and Control Code.

CC 7.2. Protection and control system of the User facility may include but not limited to the following;

(a) Over current protection

(b) Distance protection

(c) Differential protection

(d) Impedance protection

(e) load unbalance (negative sequence) protection

(f) out of step protection

(g) loss of excitation protection

(h) over/under-voltage protection

(i) over/under-frequency protection

(j) high speed automatic reclosing (HSAR)

(k) breaker failure protection

(l) any special protection scheme (SPS) or remedial action schemes (RAS)

(m) reverse power protection

CC 7.3. User shall devise and execute adequate protection system for its equipment against internal and external electrical faults. In addition, User shall implement special protection schemes against any system disturbances as required by the System Operator.

CC 7.4. SO and NGC shall jointly ensure co-ordination of protection system and schemes among Users for secure operation of the Transmission System.

CC 7.5. User shall provide the required information and signals to the SO and other relevant User(s) for monitoring and interface co-ordination, respectively.

CC 7.6. User shall obtain SO's prior approval for any changes in the protection schemes at its Facility before implementing any such change.

CC 8. **POWER QUALITY**

User shall comply with Power Quality requirements of Power Factor, Harmonic Distortion, Voltage Unbalance, Voltage Fluctuation, Flicker Severity and Rapid Voltage Changes at 132kV voltage level and below, as well as HVDC interface point with the AC transmission network. SO shall ensure compliance of Power Quality parameters as specified below.

CC 8.1. **Power Factor**

CC 8.1.1. User drawing load shall maintain Power Factor on Connection Points within the range of 0.95 lagging to unity in any half-hour period.

CC 8.1.2. The aggregate power factor for a User shall be calculated in accordance with the following formula:

$$APF = \frac{\Sigma\, P}{\sqrt{(\Sigma\ P)^2 + (\Sigma\ Q)^2}}$$

Where:

- APF is the aggregate Power Factor for the User
- Sum of Active Energy (Σ P) exchanged by the user at the Connection Point for any half-hour period;and
- Sum of Reactive Energy (Σ Q) exchanged by the user at the Connection Point for the same half-hour period.

CC 8.2. **Harmonic Distortion**

CC 8.2.1. User Plant and Apparatus shall not inject voltage harmonics on the Transmission System that exceed the limits mentioned below at the relevant Connection Point:

Table CC7: Harmonic Distortion

Voltage Level	Total Harmonic Distortion	Individual Harmonic Distortion
For Voltage ≤132	2.5%	1.5%

For Voltage >132	1.5%	1%

CC 8.2.2. User Plant and Apparatus shall not induce current harmonics on the Transmission System that exceed the limits specified in the IEEE Standard 519 (as amended from time to time), titled, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

CC 8.3. **Voltage Unbalance**

User Plant and Apparatus shall not cause the phase-to-phase voltage unbalance of the Transmission System to exceed by more than one (1)% at the Connection Point, as measured with no load and with balanced three-phase load.

CC 8.4. **Voltage Fluctuation and Flicker Severity**

CC 8.4.1. The voltage fluctuation at any Connection Point with a fluctuating Demand shall not exceed one (1) % of the nominal voltage level for step changes, which may occur repetitively. Any large voltage excursions other than step changes may be allowed up to a level of three (3) % provided that this does not pose a risk to the Transmission System or to the system of any other User.

CC 8.4.2. The Flicker Severity at any Connection Point in the Transmission System shall not exceed the limits of P_{st} =0.8 and P_{lt}=0.6, both 95th percentile values measured over a period of one week.

CC 8.5. **Rapid Voltage Changes**

User Plant and Apparatus shall not produce disturbance levels that promote Rapid Voltage Changes exceeding those specified in the table below.

Table CC8: Rapid Voltage Change Parameters

Type of Rapid Voltage Change	$\frac{\Delta U}{UN}$ Limit (%)	Timeframe
Temporary Voltage Depression	5	Must recover to nominal Voltage in 3 seconds
Step Change	3	One cycle

CC 9. **SCADA AND COMMUNICATION SYSTEM**

CC 9.1. User shall install, modify, upgrade and integrate SCADA and the associated communication system within its facility and up to the designated control center(s) to comply with monitoring, control and cyber security requirements for ensuring secure system operation.

CC 9.2. User shall provide SCADA integration readiness certificate to SO for consent/ approval before energizing its facility.

CC 9.3. User shall ensure SCADA data retention period, resolution, accuracy as per SO requirement.

CC 9.4. User shall install high resolution devices to monitor and record normal system operation and system disturbance events with following parameters but not limited to:

(a) voltage;
(b) current;
(c) active power;
(d) reactive power;
(e) frequency;
(f) power angles; and
(g) phase angle.

The detailed operational requirements of the communication facilities, signals and data to be provided by Users to the SO are specified in CC. Annex- 1 and OC 9.

CC 10. **PLANT AND APPARATUS NOMENCLATURE**

CC 10.1. User shall submit nomenclature of its new Plant and Apparatus or its modification in accordance with the specified template designed by the SO for review and approval of the SO before Testing and Commissioning of the User Facility.

CC 10.2. User shall implement clear and unambiguous labeling of its Plant and Apparatus as per the approved nomenclature by the SO and shall ensure its maintenance.

CC 10.3. User shall not alter/modify the approved nomenclature of its Plant and Apparatus without prior permission of the SO.

CC 11. **ANCILLARY SERVICES**

User(s) shall provide ancillary services to the Transmission System as per the requirement of the SO:

(a) Voltage/Reactive Power support; and

(b) Primary Frequency control.

(c) Frequency response from ESU;

(d) Synthetic Inertia;

(e) Demand Response;

(f) Black Start Capability;

(g) Hot Standby;

(h) Secondary Frequency Response normally taken through Automatic Generation Control (AGC), Load/Frequency Control (LFC), etc.;

(i) Reactive Power support from Synchronous Condenser or FACTs devices or switched shunt capacitors.

Compensation mechanism for the above ancillary services shall be administered according to the Commercial Code.

CC 12. **TESTING & COMMISSIONING**

CC 12.1. User shall perform Testing and Commissioning in accordance with technical standards and provisions of the Grid Code and/or relevant Agreement(s), witnessed jointly by SO, NGC and relevant TNO.

CC 12.2. User shall request SO for dispatch requirements during commissioning tests, as applicable, which shall be discussed and agreed before commencement and shall be subjected to SDC and OC11.

CC 12.3. User shall demonstrate to the SO that it has complied with all requirements by successfully completing the Operational Notification Procedure for Connection.

CC 12.4. User shall maintain complete and accurate records of all performance inspection, testing and monitoring that it conducts in fulfillment of its obligations under this Code for at least five (5) years that shall be made readily available to SO and relevant TNO.

CC 12.5. **Operational Notification Procedure**

The Operational Notification Procedure for connection of each User requires completion of following three-step sequential processes:

(a) Energization Operational Notification (EON);

(b) Interim Operational Notification (ION); and

(c) Final Operational Notification (FON).

CC 12.5.1. **Energization Operational Notification**

The SO will issue an EON to the User, subject to completion and verification of the EON checklist by SO, NGC and relevant TNO. Upon issuance of the EON, a User may energize its internal network and auxiliaries for the associated Plant and Apparatus by using the grid connection that is specified for the Connection Point as instructed by the SO.

CC 12.5.2. **Interim Operational Notification Procedure**

The SO will issue an ION to the User, subject to completion of the ION checklist by SO, NGC and relevant TNO. Upon receipt of the ION, a User may operate the associated Plant and Apparatus for a limited period of time, by using the grid connection that is specified for the Connection Point. The limited period of time shall be agreed with the SO and shall not be longer than six (6) months. An extension to this period of time may be granted if the User can demonstrate sufficient progress towards full compliance and outstanding issues are clearly identified. FON shall not be issued during ION period.

CC 12.5.3. **Final Operational Notification**

CC 12.5.3.1. The SO will issue a FON to the User, subject to completion of the FON checklist by SO, NGC and relevant TNO. Upon receipt of the FON, a User may operate the associated Plant and Apparatus by using the grid connection that is specified for the Connection Point.

CC 12.5.3.2. If the SO identifies a reason not to issue a FON, the User may seek relaxation.

CC 12.5.3.3. Where a request for relaxation is rejected, the SO shall have the right to refuse to allow the operation of the User until the User and the SO resolve the incompatibility and the SO considers that the User Plant and Apparatus is compliant with Grid Code. If the SO and the User do not resolve the incompatibility within a reasonable time frame, but in any case, not later than six (6) months after the notification of the rejection of the request for a relaxation, each party may refer the issue for decision to the GCRP as the case may be.

CC 12.6. A User issued with a FON shall inform the SO immediately in the following circumstances:

(a) the Plant and Apparatus is temporarily subject to either significant modification or loss of capability affecting its performance; or

(b) equipment failure leading to non-compliance with some relevant requirements.

CC 12.7. **Limited Operational Notification (LON)**

CC 12.7.1. A User shall apply to the SO for a Limited Operational Notification (LON), if User reasonably expects the circumstances described in CC 12.6 to persist for more than three (3) months.

CC 12.7.2. The SO will then issue a LON containing the following information:

(a) unresolved issues justifying the granting of the LON;

(b) responsibilities and timelines for the expected solution; and

(c) maximum period of validity which shall not exceed twelve (12) months.

The initial period granted may be shorter with the possibility of an extension if evidence is submitted to the satisfaction of the SO demonstrating that substantial progress has been made towards achieving full compliance.

CC 12.7.3. The FON shall be suspended during the period of validity of the LON with regard to the items for which the LON has been issued.

CC 12.7.4. A further extension of the period of validity of the LON may be granted upon a request for a relaxation made to the SO before the expiry of that period.

CC 12.7.5. The SO shall have the right to refuse to allow the operation of the User Plant and Apparatus, once the LON is no longer valid. In such cases, the FON shall automatically become invalid.

CC 12.7.6. If the SO does not grant an extension of the period of validity of the LON and/or if it refuses to allow the operation of the User Plant and Apparatus once the LON is no longer valid in accordance with CC 12.7, the User may refer the issue for decision to the GCRP within six (6) months after the notification of the decision by the SO.

CC 12.8. No new Plant and Apparatus of any User shall be energized or commissioned/connected prior to fulfillment of the following conditions in addition to conditions mentioned in this CC or any other sub-code of the Grid Code:

(a) Data sharing with SO and relevant User(s) has been completed for Connection of its Plant and Apparatus on approved formats.

(b) Required communication links for voice, data, SCADA have been established by the User up to SO and TNO designated sites.

(c) Operational drawing of User Plant and Apparatus or amendments in drawings of existing User Facilities have been approved by the SO.

(d) All necessary agreements, schedules, registrations etc. have been finalized and signed by all relevant parties/ departments/ utilities etc.

Facilities already Energized / Connected / Commissioned that have not fulfilled all the conditions mentioned above shall comply with the requirement.

CC 13. **POWER SUPPLIES**

User shall provide 400 / 230 V ac power supply at its Plant and Apparatus through:

(a) an auxiliary; and

(b) a standby Plant and Apparatus (diesel generator or any alternative means) capable of supplying for minimum ten (10) hours.

CC 14. **SAFETY**

CC 14.1. User shall ensure safety of personnel and equipment during construction, Testing and Commissioning of Plant and Apparatus as per Prudent Utility Practices and NEPRA Power Safety Code (Amended to date).

CC 14.2. User shall detail the demarcation of responsibility for safety of persons carrying out work or testing at the connection Site and on circuits.

CC 14.3. Detailed information on procedures and responsibilities involved in safety procedures is set out in OC.13.

SCADA SIGNALS TO BE PROVIDED BY USERS

CC.A.1. **Status Indication Signals**

Circuit Breakers, Isolators & Disconnecting/ Earth Switches positions pertinent to the status of Transformers, Transmission Lines, Generators, Busbars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Units and/or any other equipment as specified by SO, through a set of two potential free auxiliary contacts (one contact normally open and one contact normally closed when circuit breaker is open) for each circuit breaker, isolator & disconnecting switch individually;

CC.A.2. **Measurement Signals**

(a) ± Active Power, ± Reactive Power, Ampere, Voltage kV, Power Factor, Control Angles, State of Charge, Energy measurements pertinent to Transformers, Transmission Lines, Generators, Busbars, Shunt Reactors, Capacitors, SVCs, Filters, Battery Energy Storage Units and/or any other equipment as specified by SO (acting reasonably);

(b) Busbar Frequency Hz measurement at least up to 3 decimal places

(c) For generators, MW, MVAR & Power Factor will be required at alternator terminals of each Generating Unit (Gross Output);

(d) Transformers Tap Position (including generator transformers & grid connected transformers)

(e) For Transformers, Voltage kV measurement signal will be required from LV side except for generator transformer where Voltage kV Signal will be required from HV side.

(f) Real Time meteorological data e.g. Wind Speed, Wind Direction, Solar Radiation, Ambient Temperature, Atmospheric pressure, Humidity etc.

(g) Real Time Hydrological Data e.g. inflow, out flow, discharge, reservoir or pond level, tail race level etc.

CC.A.3. **Control Signals**

(a) Remote Command signals from SO to Open/ Close Circuit Breakers, Raise Lower Transformer Tap position and interrupt regulation process at Users facilities

(b) Remote Command signals from SO, including both Digital Output (Raise/ Lower) and Analog Output (Set point), to regulate active and reactive power output and ramp rate of generating unit/ interconnector/SVCs manually and/or through AGC.

(c) Remote Command Signals from SO (set point) to curtail output of Wind and Solar Plants.

(d) Remote Command Signals from SO, to change or select mode and control of operation of HVDC, Wind or Solar & BESS plants etc.

CC.A.4. **Protection Signals**

Signals pertinent to Circuit Breakers, Transformers, Transmission Lines, Generators, Busbars, Shunt Reactors, Capacitors, SVCs, telecommunication devices, GPS Clocks, HVDC System, BESS and/or any other equipment as specified by SO for fault indications. To avoid any doubt, these signals shall be provided on individual protection basis.

CC.A.5. **Other Signals**

Other Signals shall may include:

(a) Status indication signals of remote control permit switches,

(b) Status indications of PSS, AVRs, SCS, PMUs, WAMS, or any other system stability related devices

(c) Signals related to Synchro check/ Tele couplers

(d) Type of fuel in use (for generators)

(e) Feedback Set point Signals (Echo MW, Echo MVar, Echo Ramp rate etc.)

(f) Other process or event related signals

(g) Any other signals required by SO to monitor and control the performance of the User equipment.

CC.A.6. **Generators,** in addition to above mentioned relevant Signals shall also provide:

(a) Measured or derived MW output on each fuel, from Generating Units that can continuously fire on more than one fuel simultaneously;

(b) Where it is agreed between the SO and the Generator that MW &MVar signals are not available on the HV terminals (Net output), measurements shall be provided at the Grid Connected Transformer low Voltage terminals; and

(c) Remaining Secondary Fuel capability (where applicable) in MWh equivalent when running at Registered Capacity;

(d) With regard to real-time monitoring of Frequency Sensitive Mode, as described in OC.5, the Generator, Interconnector and embedded HVDC shall be equipped to transfer in real time and in a secured manner, at least the following signals:

i. status signal of Frequency Sensitive Mode (on/off);

ii. actual parameter settings for Active Power frequency response;

iii. Governor Droop; and

iv. Governor/Frequency Response Dead band.

v. Frequency Limiter Control and other such Control Functions of HVDC

vi. The SO shall specify additional signals to be provided by the User in order to verify the performance of the active power frequency response provision of participating Generating Units.

CC.A.7. **Demand Side Units** in addition to above mentioned relevant Signals shall also provide:

(a) MW and MVAR at the HV terminals of the Grid Connected Transformer;

(b) Demand Side Unit MW Response from Generation operating in Continuous Parallel Mode or Shaving Mode;

(c) Demand Side Unit MW Response from avoided Demand consumption and Generation operating in Lopping Mode, Standby Mode or Automatic Mains Failure Mode;

(d) Remaining Demand Side Unit MW Availability;

(e) Demand Side Unit MW Response from each Individual Demand Site with a Demand Side Unit MW Capacity of greater than or equal to (XXX) MW;

(f) MW Output from Generating Units with a Capacity greater than or equal to five (5) MW;

(g) VAR Output from Generating Units with a Capacity greater than or equal to five (5) MW at Individual Demand Sites with a Maximum Export Capacity specified in the Connection Agreement or DSO Connection Agreement as applicable, as required by the SO;

(h) Aggregate MW Output from Generating Units with a combined Capacity of greater than or equal to five (5) MW on an Individual Demand Site, as required by the SO; and

(i) Demand Side Unit MW Response from each Individual Demand Site that comprises the Demand Side Unit, as required by the SO.

CC.A.8. **AC & HVDC Interconnectors** shall provide:

(a) For AC Interconnectors: Relevant Signals as mentioned above and any other signals required by SO.

(b) For HVDC Interconnectors: Status Indications, Measurements, Commands Protection & Other Signals related to AC & DC Switchyard, Filters, Reactors etc., as specified by SO.

(c) Where signals and indications required to be provided by the User under CC.10.1 become unavailable or do not comply with applicable standards due to failure of the Users' technical equipment or any other reason under the control of the User, the User shall, acting in accordance with Good Industry Practice, restore or correct the signals and/or indications as soon as possible.

(d) Where, the SO, determines that because of a modification to the Transmission System or otherwise to meet a Transmission System requirement, additional signals and/or indications in relation to a User's Plant and Apparatus are required, the SO shall notify that requirement to the User. On receipt of such a notification the User shall promptly, and in accordance with Good Industry Practice, ensure that such signals and/or indications are made available at the relevant marshalling rack.

(e) Demand Side Unit Operators and Generator Aggregators shall provide the SO the specification of the method of aggregation of SCADA from multiple sites. The minimum specifications shall be agreed with the SO in advance.

VOLTAGE-AGAINST-TIME-PROFILE

Fault-ride-through profile of the DC converter stations.

The diagram represents the lower limit of a voltage-against-time profile at the connection point, expressed by the ratio of its actual value and its reference one (1) pu value in per unit before, during and after a fault. Uret is the retained voltage at the connection point during a fault, tclear is the instant when the fault has been cleared, Urec1 and trec1 specify a point of lower limits of voltage recovery following fault clearance. Ublock is the blocking voltage at the Connection Point under specific network conditions whereby the DC Facilities is allowed to block. Blocking means remaining connected to the network with no active and reactive power contribution for a time frame that shall be as short as technically feasible, and which shall be eventually agreed between the relevant TNO and SO. The time values referred to are measured from fault.

Table: Parameters for above Figure for the fault-ride-through capability of an HVDC converter station

Voltage-against-time-profile referred to section

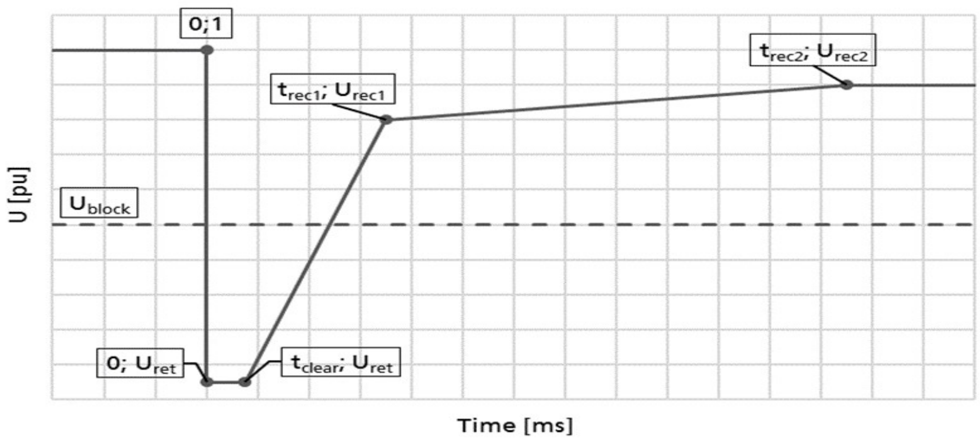


Table: Parameters for above Figure for the fault-ride-through capability of an HVDC converter station (Source: CASA Technical Code)

Voltage Parameters (pu)		Time Parameters (seconds)	
U ret	0.00-0.30	**t clear**	0.14-0.25
U rec1	0.25-0.85	**t rec1**	1.5-2.5
U rec2	0.85-0.90	**t rec2**	t rec1-10.0

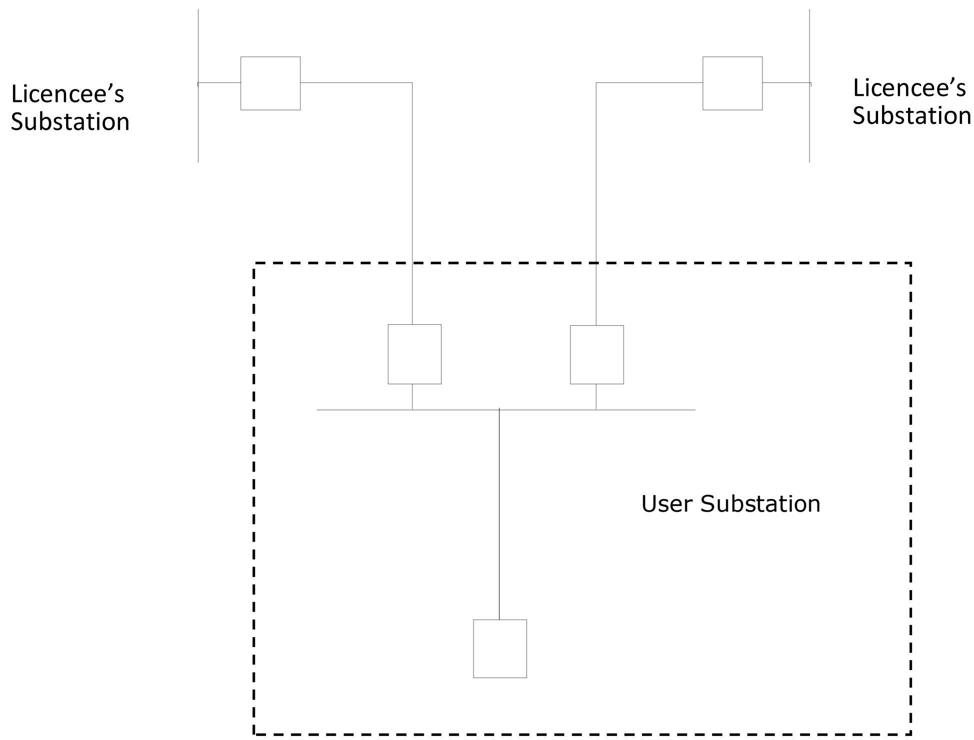
INTERCONNECTION CONFIGURATIONS FOR USERS CONNECTION

For connection of User Substation, following three configurations have been indicated which may be adopted according to the system conditions.

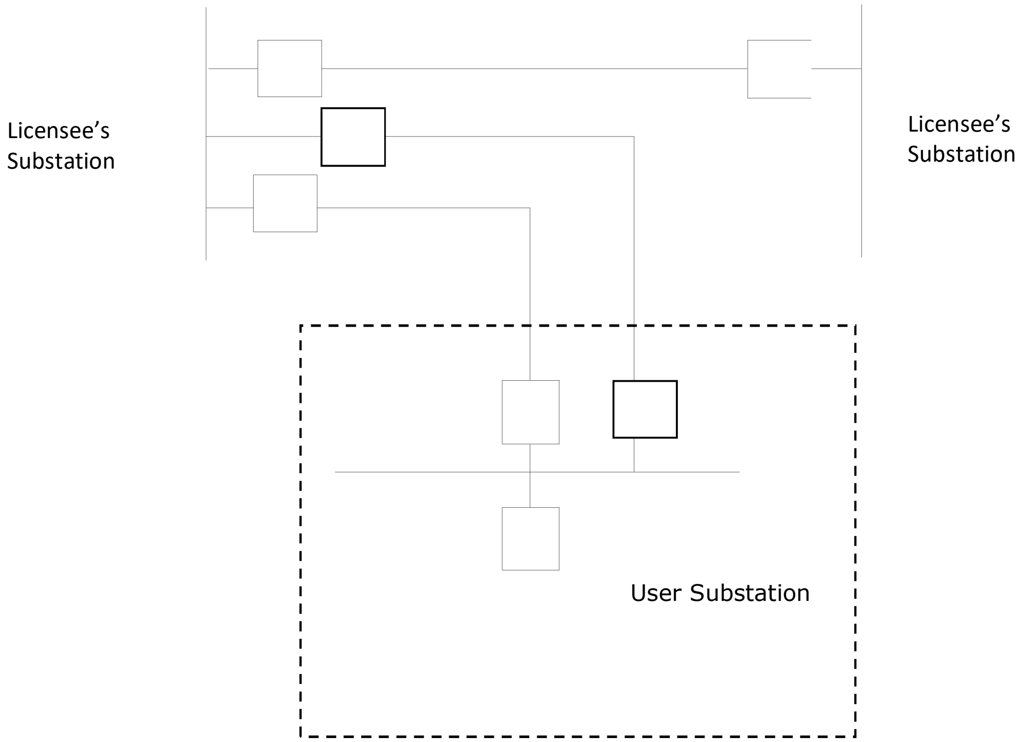
Consumer 132 kV and below	Consumer 220 kV and above	Generator 132 kV and below	Generator 220 kV and above
Scheme 1, 2 or 3	Scheme 1 or 2	Scheme 1 or 2	Scheme 1

The User may opt following configurations, which System Operator may accept after carrying out necessary system studies. Busbar and breaker configuration (single, double, one and half or ring) shall be as per system studies.

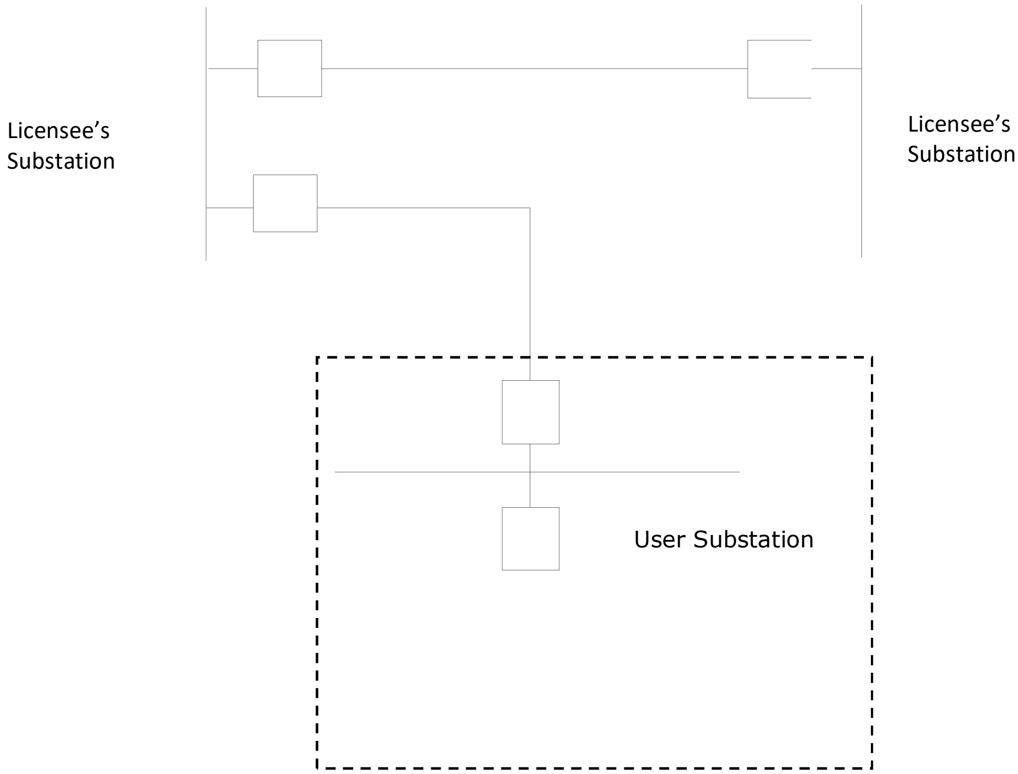
Scheme 1: INTERCONNECTION CONFIGURATIONS WITH IN-OUT ARRANGEMENT



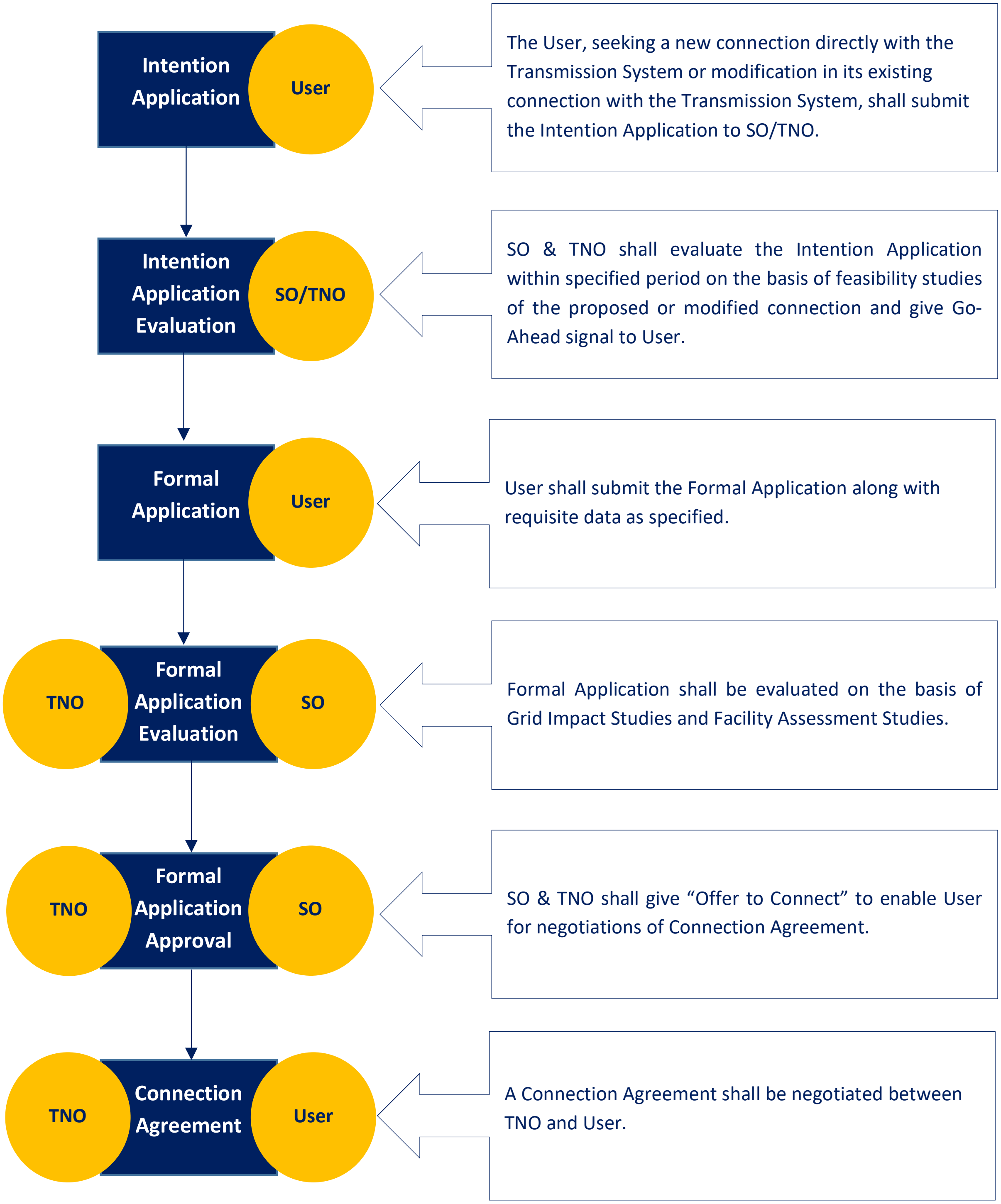
Scheme 2: **INTERCONNECTION CONFIGURATIONS (radial with N-1)**



Scheme 3: **INTERCONNECTION CONFIGURATIONS (radial)**



CONNECTION PROCESS



PROFORMA FOR SITE RESPONSIBILITY SCHEDULE (SRS)

This proforma should at least contain the following:

1. Number of Schedule, Issue, Number and Date.
2. Name of Complex and Connection Site.
3. Identification of Apparatus.
4. Name of the Owner of the Apparatus.
5. Name of the Person in charge of the Work Site (Authorized Person)
6. Item of Plant Apparatus.
7. Name of the Safety coordinator.
8. Details of the Operations carried out on each Apparatus.
9. Safety Rules and Precautions.
10. Operational Procedures.
11. Party Responsible for Undertaking Inspections, Fault Investigation and Maintenance.
12. Remarks

PROFORMA FOR SITE RESPONSIBILITY SCHEDULE

CC.A1. Principles
Principles which form the basis of developing SRS

CC.A2. Types of Schedules

a. Construction b. Commissioning
c. Control d. Operation
e. Maintenance f. Testing

CC.A3. New connection sites

CC.A4. Sub-division of connection sites; if any

CC.A5. Description of each item of plant and apparatus at the connection site.

CC.A6. Additional detail of plant and apparatus, if any.

CC.A7. Lines and cables emanating from connection sites.

CC.A8. Issuance of draft SRS

CC.A9. Accuracy confirmation by concerned parties

CC.A10. Site responsibility schedule

CC.A11. Distribution of SRS

CC.A12. Availability of site responsibility schedules (SRS)

CC.A13. Alterations/revisions to existing site responsibility schedules; if any

CC.A14. Revised site responsibility schedules

CC.A15. Finalization of site responsibility schedules

CC.A16. Urgent changes

CC.A17. Names and designation of authorized person and safety coordinators

CC.A18. De-commissioning of connection sites

CC. ANNEX- 6

PRINCIPLES AND PROCEDURES RELATING TO OPERATION DIAGRAMS

(The Operation Diagram shall include all HV Apparatus and the Connections to all external circuits including Numbering, Nomenclature, Labelling).

PRINCIPLES AND PROCEDURES RELATING TO GAS ZONE DIAGRAMS

(Areas of the Connection Sites where gas-insulated metal enclosed switchgear and/or gas-insulated HV apparatus is installed shall be depicted by a chain dotted line which intersects the Gas Zone boundaries. A Gas Zone Diagram is to be prepared for each Connection Site where a gas-insulated switchgear/apparatus has been used. These Diagrams shall conform to the Operation Diagrams in terms of Graphical symbols and Nomenclature)

APPARATUS TO BE SHOWN ON THE OPERATION AND GAS ZONE DIAGRAMS

List of all apparatus to be shown on the Operation and Gas Zone Diagrams that is installed at the Connection Sites including its present status as it pertains to the System Operation.

MINIMUM FREQUENCY RESPONSE REQUIREMENTS SCOPE

CC.A1. Scope

CC.A2. Plant Operating Range

a. Minimum Frequency Response Capability Profile in the graphical form;
b. Interpretation of Initial and Secondary Response Values by the Connecting Party in the graphical form

CC.A3. Testing of Minimum Frequency Response Capability

CC.A4. Repeatability of Response

TECHNICAL REQUIREMENTS FOR LOW FREQUENCY RELAYS

CC.A1. Low Frequency Relays

(Technical Specifications and Setting as per Connection Agreement)

CC.A2. Low Frequency Relay Voltage Supplies

(Secured voltage supply arrangement for the low frequency relay)

CC.A3. Scheme Requirements

a. Minimum dependability functional requirements at each Connection Site.

b. Outage requirements with respect to load shedding specified by the System Operator.

LIST OF MINIMUM REQUIREMENTS FOR POWER SYSTEM AND APPARATUS CONNECTED TO THE TRANSMISSION SYSTEMS

GENERATOR INFORMATION

S. No	DESCRIPTION OF REQUIRED INFORMATION	(DATA TO BE FILLED ACCORDING TO DESCRIPTION)
1	NAME OF GENERATOR	
2	LOCATION OF GENERATOR (COMPLETE ADDRESS)	
3	NAME OF OWNER OF GENERATOR (e.g., WAPDA, PEDO KPK, AJK, MR.------ IPP) AND ITS ADDRESS	
4	TYPE OF GENERATOR (HYDEL-SMALL, MEDIUM, LARGE / RUN OF RIVER, STORAGE/ LOW, MEDIUM, HIGH HEAD: THERMAL (STEAM, GAS TURBINE-OPEN CYCLE, CLOSE CYCLE, DIESEL ENGINE); NUCLEAR; WIND; SOLAR	
5	FUEL (WATER, COAL, RLNG, GAS, FO, LSFO, HSD, WIND, SOLAR RADIATION)	
6	TYPE OF AGREEMENT (e.g., BOO, BOOT, BOT)	
7	PPA SIGNING DATE	
8	EXPECTED COMMERCIAL OPERATION DATE (COD)	
9	AGREEMENT PERIOD	
10	YEAR OF RETIREMENT	
11	INSTALLED CAPACITY (MW)	
12	DERATED CAPACITY (MW)	
13	AVAILABLE CAPACITY	
14	NUMBER OF GENERATING UNITS AND THEIER CAPACITY	
15	TYPE OF GENERATORS (SYNCHRONOUS, INDUCTION)	
16	TOTAL NUMBER OF UNIT TRANSFORMERS	
17	TOTAL NUMBER OF AUXILIARY / STATION TRANSFORMERS	
18	TOTAL NO OF POWER TRANSFORMERS	
19	TYPE OF BUSBAR SCHEME (BREAKER AND A HALF, SINGLE, RING, TRANSFER)	
20	TOTAL NO OF BAYS /DIAS	
21	TOTAL NO OF CONNECTED CIRCUITS	

S. No	DESCRIPTION OF REQUIRED INFORMATION	(DATA TO BE FILLED ACCORDING TO DESCRIPTION)
22	TOTAL NO OF CIRCUIT BREAKERS	
23	ESTIMATED POWER (MW) REQUIRED FOR AUXILIARIES	
24	ESTIMATED AUXILIARY CONSUMPTION (KWH)	
25	AVAILABILITY OF BLACK START FACILITY (YES/NO)	
26	GENERATING SET CAPACITY FOR BLACK START FACILITY	
27	FUEL REQUIREMENT PER HOUR, DAY ON FULL LOAD	
28	FUEL REQUIREMENT PER HOUR, DAY ON MINIMUM LOAD (e.g., WATER, COAL, FO, GAS, WIND, SOLAR RADITATION)	
29	FUEL STORAGE CAPACITY	
30	FUEL STOCK TO BE MAINTAINED AS PER PPA	
31	HEAT RATE AS PER PPA	
32	EFFICIENCY OF PLANT (LEVELIZED)	
33	SCHEDULED OUTAGE PERIOD AS PER PPA	
34	FORCED OUTAGE HOURS ALLOWANCE AS PER PPA	
35	TARIFF TYPE (e.g., UPFRONT, COST PLUS, COMPETITIVE)	

GRID STATION INFORMATION

S. No	DESCRIPTION OF REQUIRED INFORMATION	(DATA TO BE FILLED ACCORDING TO DESCRIPTION)
1	NAME OF GRID STATION	
2	LOCATION OF GRID STATION (COMPLETE ADDRESS)	
3	NAME OF OWNER OF GRID STATION (e.g., WAPDA, DISCO, PEDO KPK, AJK, MR.------ IPP) AND ITS ADDRESS	
	TYPE OF GRID STATION (i.e., AIS or GIS)	
4	VOLTAGE LEVELS OF GRID STATION (e.g., 500/220/132/11)	
5	TYPE OF BUSBAR SCHEME (BREAKER AND A HALF, SINGLE, RING, TRANSFER)	
6	TOTAL NO OF BAYS /DIAS	
7	TOTAL NO OF POWER TRANSFORMERS	
8	TOTAL NO OF TRANSMISSION LINES CONNECTED CIRCUITS	
9	TOTAL NO OF CIRCUIT BREAKERS	
10	TYPES OF CIRCUIT BREAKERS	
11	NO OF AUXILIARY TRANSFORMERS	
12	ESTIMATED POWER (MW) REQUIRED FOR AUXILIARIES	
13	ESTIMATED AUXILIARY CONSUMPTION (KWH)	
14	NO OF REACTORS	
15	CAPCITOR BANK UNITS AND CAPACITY	
16	LAND AVAILABILITY FOR FUTURE EXTENSION (How much and for how many bay for transformer/ transmission lines/ capacitor banks/ reactors etc)	

DC CONVERTOR STATION

NAME OF CONVERTER STATION: ____________CONVERTER STATION LOCATION: ________________

S. No	DESCRIPTION	MEASUREMENT UNITS	
1	NAME OF CONVERTOR STATION	NAME	
2	RATED MW PER POLE FOR TRANSFER IN EACH DIRECTION	MW	
3	DC CONVERTOR TYPE (i.e., CURRENT "or" VOLTAGE SOURCE	NAME	
4	NUMBEROF POLES AND POLE ARRANGEMENT	NUMBER	
5	RATED DC VOLTAGE / POLE	KV	
6	RETURN PATH ARRANGEMENT (EARTH, CONDUCTOR ETC)	DESCRIPTION	
7	RATED DC CURRENT PER POLE	NAME	
8	NOMINAL AND MAXIMUM (EMERGENCY) LOADING RATE WITH DC CONVERTER IN RECTIFIER MODE	AMPERE	
9	NOMINAL AND MAXIMUM (EMERGENCY) LOADING RATE WITH DC CONVERTER IN INVERTOR MODE	BREAKER CODE	
10	MAXIMUM RECOVERY TIME, TO 90% OF PRE- FAULT LOADING, FOLLOWING THE AC SYSTEM FAULT/ TRANSIENT DC NETWORK FAULT OR SEVERE VOLTAGE DEPRESSION.	TIME IN MINUTES	
11	SINGLE LINE DIAGRAM OF COMPLETE DC NETWORK	ATTACHED/ NOT ATTACHED	
12	DETAIL OF THE COMPLETE DC NETWORK INCLUDING RESISTANCE, INDUCTANCE AND CAPACITANCE OF ALL DC CABLES AND/ OR DC LINES	ATTACHED/ NOT ATTACHED	
13	DETAIL OF ANY DC REACTORS (INCLUDING DC REACTOR RESISTANCE)	ATTACHED/ NOT ATTACHED	
14	DETAIL OF DC CAPACITOR AND/ OR DC-SIDE FILTERS THAT FORM PART OF DC NETWORK	ATTACHED/ NOT ATTACHED	
15	DETAIL OF AC FILTER REACTIVE COMPENSATION EQUIPMENT PARAMETERS	ATTACHED/ NOT ATTACHED	
16	DC CONVERTOR CONTROL SYSTEM MODEL	MODEL	
17	DETAIL OF HORMONIC ASSESSMENT INFORMATION	ATTACHED/ NOT ATTACHED	
18	**ANY OTHER INFORMATION**		

POWER GENERATORS UNIT DATA

NAME OF GENERATOR: _________________ GENERATOR LOCATION: _____________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
A	**GENERATOR IDENTIFICATION**		
1	GENERATOR TYPE	SYNCHRONOUS/INDUCTION	
2	MANUFACTURER	NAME	
3	GENERATOR SERIAL NUMBER		
B	**GENERATOR RATING CAPABILITIES**		
1	MVA RATING (NAME PLATE) (S)	MVA	
2	HYDROGEN PRESSURE (PSIG)		
3	WINDING CONNECTION	TYPE	
4	GENERATOR SPEED	RPM	
5	ANGULAR VELOCITY OF GENERATOR (ω)	RAD/ SEC	
6	RATED GENERATION VOLTAGE (PHASE TO PHASE)	KV	
7	RATED CURRENT	AMPERE	
8	POWER FACTOR (P.F) LAGGING (OVER EXCITED)	%AGE OR VALUE	
9	POWER FACTOR (P.F) LEADING (UNDER EXCITED)	%AGE OR VALUE	
10	ACTIVE (REAL) POWER (P) BASE	MW	
11	ACTIVE (REAL)POWER (P) MAXMUM	MW	
12	ACTIVE (REAL) POWER (P) MINIMUM	MW	
13	REACTIVE (IMAGINARY) POWER (Q) MAXMUM	MVAR	
14	REACTIVE (IMAGINARY) POWER (Q) MINIMUM	MVAR	
15	CONTINUOUS OPERATION FREQUENCY RANGES	HZ	
16	SHORT TIME FREQUENCY RANGE	HZ	
17	CONTINUOUS OPERATION, OPERATING VOLTAGE LIMITS	PU	
18	SHORT TIME OPERATING VOLTAGE LIMITS	PU	
19	FIELD CURRENT AT RATED LOAD	AMPERE	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
20	FIELD CURRENT AT FULL LOAD, RATED VOLTAGE AND RATED POWER FACTOR OVEREXCITED	AMPERE	
21	FIELD CURRENT AT GENERATOR RATED VOLTAGE, NO LOAD	AMPERE	
22	FIELD VOLTAGE AT RATED LOAD	V	
23	NOMINAL EXCITOR CEILING VOLTAGE (+VE POLARITY)	V OR PU	
24	NOMINAL EXCITOR CEILING VOLTAGE (-VE POLARITY)	V OR PU	
25	AIR GAP FIELD VOLTAGE WITH GENERATOR ATRATED VOLTAGE	V	
26	FIELD WINDING RESISTANCE AT OPERATING TEMPERATURE OF _______°C	OHMS	
27	SHORT CIRCUIT RATIO (SCR)		
28	DAMPING (D)		
29	DAMPING TORQUE COEFFICIENT (KD)	P.U MW/PU FREQ	
C	**INERTIA**		
1	WR^2 FOR GENERATOR	KG-M^2 OR LB-FT^2	
2	WR^2 FOR EXCITOR (IF APPLICABLE)	KG-M^2 OR LB-FT^2	
3	WR^2 FOR TURBINE	KG-M^2 OR LB-FT^2	
4	"TURBINE+GENERATING UNIT " INERTIACONSTANT (H)	MW -SEC/MVA	
D	**LOSSES AND EFFICIENCY**		
1	OPEN CIRCUIT CORE LOSSES	KW	
2	WINDAGE LOSSES	KW	
3	SEALS AND EXCITER FRICTION LOSS	KW	
4	STATOR I2R LOSS AT _______°C	KW	
5	ROTOR I2R LOSS AT _______°C	KW	
6	STRAY LOAD LOSS	KW	
7	EXCITATION LOSS	KW	
E	**GENERATOR IMPEDANCES/ REACTANCES/ RESISTANCES**		

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
-	APPARENT POWER BASE MVA	MVA	
-	VOLTAGE BASE	KV	
1	DIRECT AXIS SYNCHRONOUS REACTANCE (X_d) UNSATURATED AT OWN BASE	% AGE or P.U	
2	QUADRATURE AXIS SYNCHRONOUS REACTANCE (X_q) UNSATURATED AT OWN BASE	% AGE or P.U	
3	DIRECT AXIS TRANSIENT REACTANCE (Xd') UNSATURATED AT OWN BASE	%AGE or P.U	
4	DIRECT AXIS TRANSIENT REACTANCE (X_{ds}') SATURATED AT OWN BASE	%AGE or P.U	
5	QUADRATURE AXIS TRANSIENT REACTANCE (X_q') UNSATURATED AT OWN BASE	%AGE or P.U	
6	QUADRATURE AXIS TRANSIENT REACTANCE (X_{qs}') SATURATED AT OWN BASE	%AGE or P.U	
7	DIRECT AXIS SUB TRANSIENT REACTANCE (Xd") UNSATURATED AT OWN BASE	%AGE or P.U	
8	DIRECT AXIS SUB TRANSIENT REACTANCE (X_{ds}") SATURATED AT OWN BASE	%AGE or P.U	
9	QUADRATURE AXIS SUB TRANSIENT REACTANCE (Xq") UNSATURATED AT OWN BASE	%AGE or P.U	
10	QUADRATURE AXIS SUB TRANSIENT REACTANCE (X_{qs}") SATURATED AT OWN BASE	%AGE or P.U	
11	NEGATIVE PHASE SEQUENCE REACTANCE (X2) AT RATED VOLTAGE (UNSATURATED)	%AGE or P.U	
12	NEGATIVE PHASE SEQUENCE REACTANCE (X2s) AT RATED VOLTAGE (SATURATED)	%AGE or P.U	
13	ZERO PHASE SEQUENCE REACTANCE (X0) UNSATURATED	%AGE or P.U	
14	ZERO PHASE SEQUENCE REACTANCE (X0s) SATURATED	%AGE or P.U	
15	POSITIVE SEQUENCE ARMATURE RESISTANCE (R1) AT 100°C	%AGE or P.U	
16	NEGATIVE SEQUENCE ARMATURE RESISTANCE (R2) AT 100°C	%AGE or P.U	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
17	DIRECT CURRENT ARMATURE RESISTANCE (R_{dc}) AT 100°C	%AGE or P.U	
18	STATOR (ARMATURE) RESISTANCE (RS)	%AGE or P.U	
19	DIRECT AXIS STATOR INDUCTANCE (LSD)	%AGE or P.U	
20	QUADRATURE AXIS STATOR INDUCTANCE (LSQ)	%AGE or P.U	
21	DIRECT AXIS DAMPER WINDING LEAKAGE INDUCTANCE (L1Dλ)	%AGE or P.U	
22	QUADRATURE AXIS DAMPER WINDING 1 LEAKAGE INDUCTANCE (L1Qλ)	%AGE or P.U	
23	QUADRATURE AXIS DAMPER WINDING 2 LEAKAGE INDUCTANCE (L2Qλ)	%AGE or P.U	
24	STATOR LEAKAGE INDUCTANCE (LSλ)	%AGE or P.U	
25	FIELD RESISTANCE (RFD)	%AGE or P.U	
26	DIRECT AXIS DAMPER WINDING RESISTANCE (R1D)	%AGE or P.U	
27	QUADRATURE AXIS DAMPER WINDING 1 RESISTANCE (R1Q)	%AGE or P.U	
28	QUADRATURE AXIS DAMPER WINDING 2 RESISTANCE (R2Q)	%AGE or P.U	
29	POTIER REACTANCE (Xp)	%AGE or P.U	
30	ARMATURE LEAKAGE REACTANCE (XL)	%AGE or P.U	
F	**GENERATOR TIME CONSTANTS**		
1	DIRECT AXIS OPEN CIRCUIT TIME CONSTANT TRANSIENT (T_{do}')	SECONDS	
2	DIRECT AXIS OPEN CIRCUIT TIME CONSTANT SUB TRANSIENT (T_{do}'')	SECONDS	
3	QUADRATURE AXIS OPEN CIRCUIT TIME CONSTANT TRANSIENT (T_{qo}')	SECONDS	
4	QUADRATURE AXIS OPEN CIRCUIT TIME CONSTANT SUB TRANSIENT (T_{qo}'')	SECONDS	
5	DIRECT AXIS SHORT CIRCUIT TIME CONSTANT TRANSIENT (Td')	SECONDS	
6	DIRECT AXIS SHORT CIRCUIT TIME CONSTANT SUB TRANSIENT (Td'')	SECONDS	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
7	QUADRATURE AXIS SHORT CIRCUIT TIME CONSTANT SUB TRANSIENT (T_q'')	SECONDS	
8	ARMATURE WINDING SHORT CIRCUIT TIME CONSTANT(Ta)	SECONDS	
G	**GENERATOR CHARACTERISTIC CURVES**		
1	GENERATOR REACTIVE CAPABILITY CURVES	ATTACHED / NOT ATTACHED	
2	GENERATOR VOLTAGE- FREQUENCY CAPABILITY CURVE	ATTACHED / NOT ATTACHED	
3	GENERATOR EXCITATION “V" CURVES	ATTACHED / NOT ATTACHED	
4	GENERATOR SATURATION AND SYNCHRONOUS IMPEDANCE CURVES FULL LOAD AND NO LOAD	ATTACHED / NOT ATTACHED	
5	GENERATOR EFFICIENCY - LOAD CURVE	ATTACHED / NOT ATTACHED	
6	GENERATOR OUTPUT - AIR INLET TEMPERATURE CURVES AT VARIOUS PF	ATTACHED / NOT ATTACHED	
7	OPEN CIRCUIT AND SHORT CIRCUIT CHARACTERISTIC CURVES	ATTACHED / NOT ATTACHED	
8	PERMISSIBLE DURATION OF NEGATIVE SEQUENCE CURRENT CURVE	ATTACHED / NOT ATTACHED	
9	GENERATOR FUEL COST CURVE	ATTACHED / NOT ATTACHED	
10	GENERATOR HEAT RATE CURVE	ATTACHED / NOT ATTACHED	
11	GENERATOR INPUT-OUTPUT CURVE	ATTACHED / NOT ATTACHED	
12	GENERATOR INCREMENTAL COST CURVE	ATTACHED / NOT ATTACHED	
H	**OTHER DATA**		
1	UPWARD RAMP RATE	MW / MIN	
2	DOWNWARD RAMP RATE	MW / MIN	
3	FAST (EMERGENCY) RAMP RATE	MW / MIN	
4	STEP CHANGE INDESPATCHED LOAD	%/MINUTE	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
5	DISPATCH LEVELS	MULTIPLE (or) ANY OTHER (ONE, TWO, ETC)	
6	BASIC COST COFFICIENT “a"		
7	BASIC COST COFFICIENT “b"		
8	BASIC COST COFFICIENT “c"		

GENERATOR (UNIT) TRANSFORMER

NAME OF GENERATOR: _______________ GENERATOR LOCATION: ____________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
1	TRANSFORMER SERIAL NO	DIGITS	
2	MANUFACTURER NAME	NAME OF COMPANY	
3	RATED CAPACITY	MVA	
4	RATED VOLTAGE PRIMARY	KV	
5	RATED VOLTAGE SECONDARY	KV	
6	RATED VOLTAGE TERTIARY	KV	
7	NOMINAL VOLTAGE RATIO, PRIMARY/SECONDARY	DIGITS	
8	NO OF TAPS	NUMBER	
9	TAP SIDE	HV/LV	
10	MAXIMUM TAP VOLTAGE	KV	
11	MINIMUM TAP VOLTAGE	KV	
12	BASE VOLTAGE	KV	
13	BASE MVA	MVA	
14	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND MAXIMUM TAP	%AGE	
15	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND MINIMUM TAP	%AGE	
16	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND NOMINAL (PRINCIPAL)TAP	%AGE	
17	ZERO PHASE SEQUENCE IMPEDANCE	%AGE	
18	TAP CHANGER RANGE	+% TO -%	
19	TAP CHANGER STEP SIZE	%	
20	TAP CHANGER TYPE	ON LOAD / OFF LOAD	
21	EARTHING PRIMARY	OHM	
22	EARTHING SECONDARY	OHM	
23	VECTOR GROUP		
24	MAGNETIZING CURVE	ATTACHED / NOT ATTACHED	
25	TOTAL IRON LOSSES/CORELOSSES/NO LOAD LOSSES (THREE PHASE)	WATT	
26	TOTAL COPPER LOSSES / WINDING LOSSES / LOAD LOSSES (THREE PHASE)	WATT	

EXCITATION SYSTEM (AVR and EXCITER PARAMETERS)

NAME OF GENERATOR: ____________________ GENERATOR LOCATION: ___________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
1	TYPE OF EXCITOR	ROTATING (AC OR DC GENERATOR) OR STATIC (THYRISTOR)	
2	MANUFACTURER	NAME	
3	BASE VOLTAGE	VOLT	
4	REGULATOR REFERENCE VOLTAGE SETTING (V_{REF})	VOLT (or) PU	
5	REGULATOR INPUT VOLTAGE (V_I)	VOLT (or) PU	
6	VOLTAGE REGULATOR INPUT VOLTAGE MAXIMUM or MAXIMUM INTEGRAL CONTROL ACTION VOLTAGE (V_{IMAX})	VOLT (or) PU	
7	VOLTAGE REGULATOR INPUT VOLTAGE MINIMUM or MINIMUM INTEGRAL CONTROL ACTION VOLTAGE(V_{IMIN})	VOLT (or) PU	
8	REGULATOR OUTPUT VOLTAGE (V_R)	VOLT (or) PU	
9	VOLTAGE REGULATOR OUTPUT VOLTAGE MAXIMUM LIMIT ''or'' POWER CONVERTOR POSITIVE CEILING VOLTAGE (V_{RMAX})	VOLT (or) PU	
10	VOLTAGE REGULATOR OUTPUT VOLTAGE MINIMUM LIMIT ''or'' POWER CONVERTOR NEGATIVE CEILING VOLTAGE(V_{RMIN})	VOLT (or) PU	
11	MAXIMUM PROPOTIONAL CONTROL ACTION VOLTAGE (VPMAX)	VOLT (or) PU	
12	MINIMUM PROPOTIONAL CONTROL ACTION VOLTAGE (VPMIN)	VOLT (or) PU	
13	AUXILIARY SIGNAL (VS)	VOLT (or) PU	
14	EXCITER VOLTAGE AT WHICH EXCITER SATURATION IS DEFINED	VOLT (or) PU	
15	MAXIMUM EXCITER FIELD CURRENT FEED BACK SIGNAL (VHMAX)	VOLT (or) PU	
16	EXCITER FIELD CURRENT LIMIT REFERENCE (VFELIM)	VOLT (or) PU	
17	VOLTAGE REGULATOR TIME CONSTANT (TA)	SECONDS	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (separate column for each Unit)
18	VOLTAGE REGULATOR LAG TIME CONSTANT (TB)	SECONDS	
19	VOLTAGE REGULATOR LEAD TIME CONSTANT (TC)	SECONDS	
20	DERIVATIVE FILTER TIME CONSTANT (TD) ''or'' REGULATOR DERIVATIVE BLOCK TIME CONSTANT (TDR)	SECONDS	
21	EXCITER TIME CONSTANT or ROTATING EXCITER TIME CONSTANT (TE)	SECONDS	
22	EXCITATION CONTROL SYSTEM STABILIZER TIME CONSTANT (TF) ‘’or'' RATEFEEDBACK EXCITATION SYSTEM STABILIZER TIME CONSTANT (TF)	SECONDS	
23	EXCITER FIELD CURRENT LIMITER TIME CONSTANT (TH)	SECONDS	
24	RESETTING TIME (TR) ‘’or'' REGULATED OUTPUT FILTER TIME CONSTANT ‘’or'' REGULATOR INPUT FILTER TIME CONSTANT	SECONDS	
25	RHEOSTAT TIME CONSTANT (TRH)	SECONDS	
27	VOLTAGE REGULATOR GAIN (KA)	PU	
28	RECTIFIER LOADING FACTOR PROPORTIONAL TO COMMUTATING REACTANCE (KC)	PU	
29	DEMAGNETIZATION FACTOR ‘’or'' DERIVATIV GAIN (KD) ‘’or'' REGULATOR DERIVATIVE GAIN(KDR)	PU	
30	EXCITER CONSTANT RELATED TO SELF EXCITED FIELD or ROTATING EXCITER GAIN (KE)	PU	
31	EXCITATION CONTROL SYSTEM STABILIZER GAIN (KF)	PU	
32	EXCITER FIELD CURRENT LIMITER GAIN (KH)	PU	
33	CURRENT CIRCUIT GAIN ‘’or'' AVR INTEGRAL GAIN (KI) ‘’or'' REGULATOR INTEGRAL GAIN (KIR)	PU	
34	VOLTAGE REGULATOR INTEGRAL GAIN (KIA)		
34	POTENTIAL CIRCUIT GAIN ‘’or'' AVR PROPOTIONAL GAIN (KP)'' or ''REGULATOR PROPORTIONAL GAIN (KPR)	PU	
35	VOLTAGE REGULATOR PROPORTIONAL GAIN (KPA)		
36	TERMINAL VOLTAGE TRANSDUCER TIME CONSTANT (TR)	PU	
37	EXCITER SATURATION FUNCTION (SE)	-	

GENERATING UNITS' STABILIZER DATA

NAME OF GENERATOR: ______________________ GENERATOR LOCATION: ____________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER (List information in separate column for each Unit)
1	TYPE OF STABILIZER		
2	STABILIZER MODEL		
3	GAIN BLOCK DATA		
4	PSS Gain (List All K_s)		
5	WASH OUT CIRCUIT DATA (HIGH PASS FILTER)		
6	Wash-out Time constant (Mention all Time Constants separately)		
7	PHASE COMPENSATION BLOCK DATA		
8	LIMITER DATA		
9	PSS output limiter "max" VSTMAX		
10	PSS output limiter "min" VSTMIN		
11	LEAD / LAG TIME CONSTANT		
12	Lead Time constant (Mention all Time Constants)		
13	Integral Time constant (T8)		
14	Ramp-tracking time constant (T9)		
15	Filter time constant (T10)		

GOVERNOR DATA

NAME OF GENERATOR: _____________ GENERATOR LOCATION: ____________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
A	**HYDEL TURBINE**		
1	PERMANENT SPEED DROOP “R" (i.e., RECIPROCAL OF PROPORTIONAL GAIN KP)		
2	TEMPORARY DROOP (r)		
3	GOVERNOR TIME CONSTANT (Tr)		
4	FILTER TIME CONSTANT (Tf)		
5	SERVO TIME CONSTANT (Tg)		
6	GATE VELOCITY LIMIT (VELM)		
7	MAXIMUM GATE LIMIT (GMAX)		
8	MINIMUM GATE LIMIT (GMIN)		
9	WATER TIME CONSTANT (TW)		
10	TURBINE GAIN (At)		
11	TURBINE DAMPING (Dturb)		
12	NO LOAD FLOW (qNI)		
B	**GAS TURBINE**		
1	PERMANENT SPEED DROOP “R" (i.e., RECIPROCAL OF PROPORTIONAL GAIN KP)		
2	GOVERNOR TIME CONSTANT (T1)		
3	COMBUSTION CHAMBER TIME CONSTANT (T2)		
4	LOAD LIMIT TIME CONSTANT (EXHAUST GAS MEASUREMENT TIME)- (T3)		
5	LOAD LIMIT FEED BACK GAIN (KT)		
6	SPEED DAMPING COEFFICIENT OF GAS TURBINE ROTOR (Dturb)		
7	OPERATIONAL CONTROL HIGH LIMIT ON FUEL VALVE OPENING (V MAX)		
8	LOW OUTPUT CONTROL LIMIT ON FUEL VALVE OPENING (V MIN)		
9	AMBIENT TEMPERATURE LOAD LIMIT (AT)		
C	**STEAM TURBINE**		

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
1	PERMANENT SPEED DROOP “R" (i.e., RECIPROCAL OF PROPORTIONAL GAIN KP)		
2	GOVERNOR TIME CONSTANT (T1)		
3	COMBUSTION CHAMBER TIME CONSTANT (T2)		
4	LOAD LIMIT TIME CONSTANT (EXHAUST GAS MEASUREMENT TIME)- (T3)		
5	LOAD LIMIT FEED BACK GAIN (KT)		
6	SPEED DAMPING COEFFICIENT OF GAS TURBINE ROTOR (Dturb)		
7	OPERATIONAL CONTROL HIGH LIMIT ON FUEL VALVE OPENING (V MAX)		
8	LOW OUTPUT CONTROL LIMIT ON FUEL VALVE OPENING (V MIN)		
9	AMBIENT TEMPERATURE LOAD LIMIT (AT)		
D	**RECIPROCATING ENGINE**		
1			
2			
E	**ANY OTHER DATA**		
1			
2			

PRIME MOVER DATA

NAME OF GENERATOR: ________________ GENERATOR LOCATION: ___________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
	HYDEL TURBINE		
1	RATED CAPACITY	MW	
2	WATER TIME CONSTANT	SECOND	
3	INERTIA CONSTANT (H)	SECOND	
4	RATED SPEED	RPM	
5	MAXIMUM SPEED	RPM	
6	MINIMUM SPEED	RPM	
	STEAM TURBINE		
1	RATED CAPACITY	MW	
2	POWER FRACTION FOR HIGH PRESSURE (HP), (INTERMEDIATE PRESSURE(IP) AND LOW PRESSURE (LP) TURBINE		
3	FUNCTIONAL DESCRIPTION AND BLACK DIAGRAM SHOWING TRANSFER FUNCTION OF INDIVIDUAL ELEMENT OF GOVERNOR, TURBINE AND BOILER	ATTACHED / NOT ATTACHED	
4	HP STEAM EXTRACTION RANGE (EXPRESSED, IN TERMS OF THE BOILER RATED OUTPUT)		
5	DETAIL OF HP STEAM EXTRACTION VALVES	ATTACHED / NOT ATTACHED	
6	GENERAL BOILER CONTROL STRATEGY	ATTACHED / NOT ATTACHED	
7	TEST DATA / REPORTS LOAD REJECTION DATA LOAD STEP RESPONSE TESTS FREQUENCY RESPONSE TEST	TESTS CONDUCTED/ DATA ATTACHED	
8	CONTROL AND INTERCEPT VALVE CURVES POSITION VS. SIGNAL VALVE OPENING VS SIGNAL CLOSING / OPENING SPEED TESTS	ATTACHED / NOT ATTACHED	
9	RATED SPEED	RPM	
10	MAXIMUM SPEED	RPM	
11	MINIMUM SPEED	RPM	

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
	GAS TURBINE OPEN CYCLE AND COMBINED CYCLE		
1	RATED CAPACITY	MW	
2	PERFORMANCE DATA /CURVES POWER VS FUEL CONSUMPTION EXHAUST TEMPERATURE VS. FUEL CONSUMPTION POWER VS AMBIENT TEMPERATURE POWER VS SPEED INLET GUIDE VAN EFFECT	ATTACHED / NOT ATTACHED	
3	FUNCTIONAL DESCRIPTION AND BLACK DIAGRAM OF GAS TURBINE UNITS SHOWING TRANSFER FUNCTION OF INDIVIDUAL ELEMENT INCLUDING EFFECT OF AMBIENT TEMPERATURE	ATTACHED / NOT ATTACHED	
4	TEST DATA / REPORTS LOAD REJECTION DATA LOAD STEP RESPONSE TESTS FREQUENCY RESPONSE TEST	TESTS CONDUCTED/ DATA ATTACHED	
5	RATED SPEED	RPM	
6	MAXIMUM SPEED	RPM	
7	MINIMUM SPEED	RPM	

WIND TURBINE GENERATOR

NAME OF GENERATOR: ___________________ GENERATOR LOCATION: ______________________

S. No	DESCRIPTION	MEASUREMENT UNITS	UNIT NUMBER
1	RATED CAPACITY	MW	
2	GENERATOR TYPE: CAGE ROTOR, DOUBLY FED INDUCTION GENERATOR OR SYNCHRONOUS, CONSTANT SPEED OR VARIABLE SPEED		
3	INERTIA CONSTANT (H)	SECOND	
4	POWER CONVERTER RATING WHERE APPLICABLE		
5	FREQUENCY TOLERANCES (I) FREQUENCY RANGE WITHIN WHICH CONTINUOUS OPERATION IS GURANTEED (II) TIME BASED CAPABILITIES FOR FREQUENCIES LOWER AND ABOVE THE LIMITS WHERE CONTINUOUS OPERATION IS GURANREED	HZ	
6	VOLTAGE TOLERANCES (I) CONTINUOUS OPERATION (II) TIME BASED CAPABILITIES FOR VOLTAGES LOWER AND ABOVE THE LIMITS WHERE CONTINUOUS OPERATION IS GURANREED	KV	
7	LOW VOLTAGE RIDE THROUGH (LVRT / FRT) -- CURVE SHOWING THE TOLERABLE DROP IN VOLTAGE, SETTING TIME TO RESUME NORMAL OUTPUT	KV -MIN	
8	UNBALANCE LOADING: ----NEGATIVE PHASE SEQUENCE WITHSTAND	MW	
9	ACTIVE POWER REGULATION: ----RAMP RATE (% OF RATED OUTPUT PER MINUTE)	MW/ MIN	
10	FREQUENCY CONTROL: ----FREQUENCY RESPONSE (REGULATE THE OUTPUT ABOVE A CERTAIN DEFINED FREQUENCY, SAY 50.2)	HZ	
11	REACTIVE POWER CAPABILITY: ----LIMITS ON LAGING AND LEADING POWER FACTOR WITHIN WHICH THE RATED OUTPUT CAN BE GURANTEED	MVAR	
12	REACTIVE POWER CAPABILITY: ----P-Q CAPABILITY CURVE	ATTACHED / NOT ATTACHED	
13	MINIMUM WIND SPEED LIMIT REQUIRED FOR OPERATION	M/SECOND	
14	MAXIMUM WIND SPEED LIMIT REQUIRED FOR OPERATION	M/SECOND	
15	FLICKER LIMITATION		
16	HARMONICS WITH STANDING LEVEL		

TRANSMISSION LINES DATA

NAME OF TRANSMISSION LINE: ________________ OWNER OF TRANMSISSION LINE: ___________

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSMISSION LINE NUMBER
1	NAME OF TRANSMISSION LINE	NAME	
2	STATION 1	NAME	
3	STATION 2	NAME	
4	VOLTAGE KV	KV	
5	CIRCUIT NO	NUMBER	
6	LENGTH OF LINE	KM	
7	CONDUCTOR NAME	NAME	
8	NO OF CONDUCTORS PER PHASE (NO OF BUNDLE CONDUCTORS)	NUMBER	
9	CONTROLLING BREAKER (S) AT STATION -1	BREAKER CODE	
10	MANUFACTURER NAME OF CONTROLLING BREAKER (S) AT STATION -1	NAME	
11	CT RATIO OF BREAKER(S) AT STATION -1 FOR PROTECTION	AMP RATIO	
12	CT RATIO OF BREAKER(S) AT STATION -1 FOR METERING	AMP RATIO	
13	CONTROLLING BREAKER (S) AT STATION -2	BREAKER CODE	
14	MANUFACTURER NAME OF CONTROLLING BREAKER (S) AT STATION -2	NAME	
15	CT RATIO OF BREAKER(S) AT STATION -2 FOR PROTECTION	AMP RATIO	
16	CT RATIO OF BREAKER(S) AT STATION -2 FOR METERING	AMP RATIO	
17	THERMAL LOADING CAPACITY OF TRANSMISSION LINE	AMP / MW	
18	SURGE IMPEDANCE LOADING (SIL)	MW	
19	SIL FACTOR (ST. CLAIR CURVE)	NUMBER	
20	LOADING LIMIT FIXED BY FIELD FORMATION	AMP / MW	
21	POSITIVE SEQUENCE PARAMETERS BASE MAVA	VALUE OF BASE MAVA	
22	POSITIVE SEQUENCE RESISTANCE (R1)	OHM	
23	POSITIVE SEQUENCE RESISTANCE (R1) ON BASE	PERCENTAGE / P.U	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSMISSION LINE NUMBER
	MAVA		
24	POSITIVE SEQUENCE REACTANCE (X1)	OHM	
25	POSITIVE SEQUENCE REACTANCE ON (X1) BASE MAVA	PERCENTAGE / P.U	
26	POSITIVE SEQUENCE SUSCEPTANCE (B1)	MOHS	
27	POSITIVE SEQUENCE SUSCEPTANCE (B1) ON BASE MVA	PERCENTAGE / P.U	
28	ZERO SEQUENCE RESISTANCE (R0)	OHM	
29	ZERO SEQUENCE RESISTANCE (R0) ON BASE MAVA	PERCENTAGE / P.U	
30	ZERO SEQUENCE REACTANCE (X0)	OHM	
31	ZERO SEQUENCE REACTANCE ON (X0) BASE MAVA	PERCENTAGE / P.U	
32	ZERO SEQUENCE SUSCEPTANCE (B0)	MOHS	
33	ZERO SEQUENCE SUSCEPTANCE (B0) ON BASE MVA	PERCENTAGE / P.U	
34	NUMBER OF TOWERS OF TRANSMISSION LINE	NUMBERS	
35	TYPE OF TOWERS	TYPE (S)	
36	SINGLE CIRCUIT TOWERS "or" DOUBLE CIRCUIT	SINGLE / DOUBLE	
37	IF DOUBLE CIRCUIT TOWERS INSTALLED, THEN DOUBLE CIRCUIT EXIST "or" NOT EXIST	EXIST/ NOT EXIST	
38	IF DOUBLE CIRCUIT EXIST, THEN NAME OF DOUBLE CIRCUIT TRANSMISSION LINE	NAME	

POWER TRANFORMER DATA

NAME OF GENERATORSWITCH YARD / GRID STATION: ________________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: _____________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSFORMER NUMBER
1	TRANSFORMER SERIAL NO	DIGITS	
2	MANUFACTURER NAME	NAME OF COMPANY	
3	COMMISSIONING DATE	DATE	
4	TYPE OF TRANSFORMER	TWO WINDING / THREE WINDING / AUTO TRANSFORMER / AUTO TRANSFORMER WITH TERTIARY	
5	NO OF UNITS (i.e., ONE THREE PHASE UNIT OR THREE SINGLE PHASE UNITS)	ONE-3P UNIT “or" THREE SP. UNITS	
6	RATED CAPACITY	MVA	
7	VECTOR GROUP (e.g., DY11, DD10 ETC.)	NAME OF GROUP	
8	YEAR OF MANUFACTURING	YEAR	
9	YEAR OF COMISSIONING	YEAR	
10	STANDARD/ CLASS	SPECIFICATION	
11	TYPE OF COOLING	AN, AF, ON, OF, ANOF, AFOF, AFON, ONWF,	
12	MAX RATED CAPACITY AT ULTIMATE COOLING METHOD	MVA AT (COOLING METHOD)	
13	RATED VOLTAGE PRIMARY	KV	
14	RATED VOLTAGE SECONDARY	KV	
15	RATED VOLTAGE TERTIARY	KV	
16	NOMINAL VOLTAGE RATIO, PRIMARY/SECONDARY	DIGITS	
17	RATED CURRENT PRIMARY	AMP	
18	RATED CURRENT SECONDARY	AMP	
19	RATED CURRENT TERTIARY	AMP	
20	MAX RATED CURRENT AT ULTIMATE COOLING METHOD	AMP AT (COOLING METHOD)	
21	NO LOAD EXCITATION CURRENT	AMP	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSFORMER NUMBER
22	NO OF TAPS	NUMBER	
23	TAP SIDE	HV/LV	
24	TAP CHANGER TYPE	ON LOAD / OFF LOAD	
25	TAP CHANGER RANGE	+% TO -%	
26	TAP CHANGER STEP SIZE	% (OR) PU	
27	NOMINAL TAP POSITION	NO	
28	MAXIMUM TAP POSITION	NO	
29	MINIMUM TAP POSITION	NO	
30	MAXIMUM TAP VOLTAGE	KV	
31	MINIMUM TAP VOLTAGE	KV	
32	BASE VOLTAGE	KV	
33	BASE MVA	MVA	
34	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND MAXIMUM TAP	%AGE	
35	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND MINIMUM TAP	%AGE	
36	POSITIVE SEQUENCE IMPEDANCE AT OWN BASE AND NOMINAL (PRINCIPAL)TAP	%AGE	
37	ZERO PHASE SEQUENCE IMPEDANCE	%AGE	
38	TOTAL IRON LOSSES/CORELOSSES/NO LOAD LOSSES (THREE PHASE)	WATT	
39	TOTAL COPPER LOSSES / WINDING LOSSES / LOAD LOSSES (THREE PHASE)	WATT	
40	REACTANCE BETWEEN PRIMARY AND SECONDARY WINDING (Z1-2) IN THREE WINDING TRANSFORMER	OHM	
41	BASE MVA FOR PRIMARY AND SECONDARY WINDING FOR THREE IN THREE WINDING TRANSFORMER	MVA1-2	
42	%AGE "or "PU REACTANCE BETWEEN PRIMARY AND SECONDARY WINDING (Z1-2) IN THREE WINDING TRANSFORMER	% or PU	
43	REACTANCE BETWEEN PRIMARY AND TERTIARY WINDING (Z1-3) IN THREE WINDING TRANSFORMER	OHM	
44	BASE MVA FOR PRIMARY AND TERTIARY WINDING FOR THREE IN THREE WINDING TRANSFORMER	MVA1-3	

S. No	DESCRIPTION	MEASUREMENT UNITS	TRANSFORMER NUMBER
45	%AGE "or "PU REACTANCE BETWEEN PRIMARY AND TERTIARY WINDING (Z1-3) IN THREE WINDING TRANSFORMER	% or PU	
46	REACTANCE BETWEEN SECONDARY AND TERTIARY WINDING (Z2-3) IN THREE WINDING TRANSFORMER	OHM	
47	BASE MVA FOR SECONDARY AND TERTIARY WINDING FOR THREE IN THREE WINDING TRANSFORMER	MVA2-3	
48	%AGE "or "PU REACTANCE BETWEEN SECONDARY AND TERTIARY WINDING (Z2-3) IN THREE WINDING TRANSFORMER	% or PU	
49	WINDING CONTACT TYPE PRIMARY	DELTA / STAR	
50	GROUNDING RESISTANCE	OHM	
51	GROUNDING REACTANCE PRIMARY	OHM	
52	GROUNDING TYPE PRIMARY	RESISTANCE / INDUCTANCE ETC	
53	NO OF PRIMARY TRANSFOMER	UNITS	
54	WINDING CONTACT TYPE SECONDARY	DELTA / STAR	
55	GROUNDING RESISTANCE SECONDARY	OHM	
56	GROUNDING REACTANCE SECONDARY	OHM	
57	GROUNDING TYPE SECONDARY	RESISTANCE / INDUCTANCE ETC	
58	NO OF SECONDARY TRANSFOMER	UNITS	
59	WINDING CONTACT TYPE TERTIARY	DELTA / STAR	
60	GROUNDING RESISTANCE TERTIARY	OHM	
61	GROUNDING REACTANCE TERTIARY	OHM	
62	GROUNDING TYPE TERTIARY	RESISTANCE / INDUCTANCE ETC	
63	NO OF TERTIARY TRANSFOMER	UNITS	
64	EARTHING PRIMARY	OHM	
65	EARTHING SECONDARY	OHM	
66	CT USED FOR CURRENT MEASUREMENT	AMP	
67	MAGNETIZING CURVE	ATTACHED / NOT ATTACHED	
68	TABLE OF CURRENT AND VOLTAGE WITH RESPECT TO TAP POSITION	ATTACHED / NOT ATTACHED	

BUSBAR DATA

NAME OF GENERATORSWITCH YARD / GRID STATION: ________________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: _____________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	BUSBAR NUMBER
	AC SUB STATIONS		
1	BUS BAR SCHEME USED FOR BUSBAR (i.e., DOUBLE BUS BAR BREAKER AND HALF, TRANSFER BUS, SINGLE BUSBAR SINGLE BREAKER ETC)	NAME	
2	BUSBAR TYPE	SOLID BARS / HOLLOW TUBE, RECTANGULAR, ROUND, ETC	
3	CONDUCTOR / TUBE NAME FOR BUSBAR	NAME	
4	MATERIAL OF CONDUCTOR (i.e., COPPER, ALUMINIUM, ALUMINIUM ALLOY ETC) USED FOR BUSBAR	NAME	
5	AMPERE CAPACITY OF BUS BAR BUSBAR	AMP	
6			
	HVDC CONVERTOR STATION		
7			
8			

CIRCUIT BREAKER DATA

NAME OF GENERATORSWITCH YARD / GRID STATION: ________________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: _____________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	BREAKER NUMBER
1	**VOLTAGE LEVEL**		
2	CIRCUIT BREAKER CODE	CODE	
3	BREAKER MANUFACTURER NAME	NAME	
4	INTURRUPTING MEDIA USED FOR C. B	SF6, AIR PRESSURIZED, OIL, VACCUM ETC	
5	OPERATING MECHANISUM USED FOR C. B	HYDRAULIC. PNUMETIC, MOTOR, SPRING ETC	
6	NO OF INTURREPTUE PER POLE OF C. B	NUMBERS	
7	C.B COMMISIONING DATE	DATE	
8	ASYMMETRICAL FAULT RATING	AMPERE	
9	SYMMETRICAL FAULT RATING	AMPERE	
10	RATED IMPULSE STANDING VOLTAGE	KV	
11	RATED NORMAL CURRENT RATING	AMPERE	
12	CT RATIO USED FOR PROTECTION	RATIO OF AMPS	
13	CT RATIO USED FOR METERING	RATIO OF AMPS	
14	CT TYPE USED FOR 765 KV BREAKER	DOUBLE CORE, MULTICORE WITH RATIO ____/____/____/____	
15	**___ KV DC BREAKER**		
16	___ KV CIRCUIT BREAKER CODE	CODE	
17	___ KV BREAKER MANUFACTURER NAME	NAME	
18	INTURRUPTING MEDIA USED FOR ___ KV C. B	SF6, AIR PRESSURIZED, OIL, VACCUM ETC	
19	OPERATING MECHANISUM USED FOR ___ KV C. B	HYDRAULIC. PNUMETIC, MOTOR, SPRING ETC	
20	NO OF INTURREPTUE PER POLE OF ___ KV C. B	NUMBERS	
21	___ KV C.B COMMISIONING DATE	DATE	
22	___ KV C.B ASYMMETRICAL FAULT RATING	AMPERE	

S. No	DESCRIPTION	MEASUREMENT UNITS	BREAKER NUMBER
23	___ KV C.B SYMMETRICAL FAULT RATING	AMPERE	
24	___ KV C.B RATED IMPULSE STANDING VOLTAGE	KV	
25	___ KV C.B RATED NORMAL CURRENT RATING	AMPERE	
26	___ KV C.B CT RATIO USED FOR PROTECTION	RATIO OF AMPS	
27	___ KV C.B CT RATIO USED FOR METERING	RATIO OF AMPS	
28	CURRENT MEASURING DEVICE TYPE USED FOR ___ KV BREAKER		
29			
30	ANY OTHER INFORMATION		
31			

ISOLATORS DATA

NAME OF GENERATORSWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: _____________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	ISOLATOR NUMBER
1	**AC VOLTAGE LEVEL**		
2	ISOLATOR CODE	CODE	
3	ISOLATOR MANUFACTURER NAME	NAME	
4	INTURRUPTING MEDIA	SF6, AIR PRESSURIZED, OIL, VACCUM ETC	
5	OPERATING MECHANISUM	HYDRAULIC. PNUMETIC, MOTOR, ETC	
	TYPE OF ISOLATOR (VERTICAL, HORIZONTAL PENTOGRAPH, etc.,)	NAME	
7	COMMISIONING DATE	DATE	
8	AMPERE CAPACITY	AMPERE	
	___ KV DC		
1	___ KV ISOLATOR CODE	CODE	
2	___ KV ISOLATOR MANUFACTURER NAME	NAME	
3	INTURRUPTING MEDIA USED FOR ___ KV ISOLATOR	SF6, AIR PRESSURIZED, OIL, VACCUM ETC	
4	OPERATING MECHANISUM USED FOR ___ KV ISOLATOR	HYDRAULIC. PNUMETIC, MOTOR, ETC	
5	TYPE OF ___ KV ISOLATOR (VERTICAL, HORIZONTAL PENTOGRAPH, etc.,)	NAME	
6	___ KV ISOLATOR COMMISIONING DATE	DATE	
7	___ KV ISOLATOR AMPERE CAPACITY	AMPERE	
	ANY OTHER INFORMATION		

SHUNT REACTORS DATA

NAME OF GENERATORSWITCH YARD / GRID STATION: ______________________________

LOCATION OF GENERATOR-SWITCH YARD / GRID STATION: _____________________________

S. No	DESCRIPTION	MEASUREMENT UNITS	REACTOR -1
1	SHUNT REACTOR CODE	CODE NO	
2	SHUNT REACTOR TYPE	NAME	
3	MANUFACTRUER NAME		
4	VOLTAGE KV		
5	CAPACITY OF REACTOR	MVAR	
4	INDUCTANCE OF REACTOR	HENERY	
5	REACTANCE OF REACTOR	OHM	
6	BASE OF REACTOR	MVAR	
7	% AGE REACTANCE OF REACTOR ON OWN BASE	% "or" PU	
8	LINE NAME WITH WHICH REACTOR INSTALLED	NAME	
9	REACTOR CONTROL (C.B "or" ISOLATOR)	NAME	
10	REACTOR CONTROLLING BREAKER / ISOLATOR ID	CODE NO	
11	ANY OTHER INFO		

OPERATION CODE

OC 1. OPERATING OBJECTIVES AND PRINCIPLES

OC 1.1. Introduction

The Operation Code (OC) specifies the technical and operating criteria, and procedures to be followed by the System Operator (SO) and Code Participants in the operation of the National Grid. The System Operator shall be responsible for the Safe, Secure and Reliable operation of the National Grid. The Code Participants shall follow the technical design and operating criteria and procedures as specified in the Grid Code.

The functions and responsibilities of the System Operator are subject to the conditions as specified in the System Operator license, and include Operation, Control and Discipline of the Transmission System.

Operation Code is comprised of 13 sub-codes as mentioned below:

(a) OC 1: Operating Objectives and Principles.

(b) OC 2: Operational Demand Forecasts

(c) OC 3: Demand Management

(d) OC 4: Operational Planning

(e) OC 5: System Services

(f) OC 6: Network Control

(g) OC 7: HVDC Operation and Performance

(h) OC 8: Operational Liaison

(i) OC 9: Operational Communication and Data Retention

(j) OC 10: Operational Testing

(k) OC 11: Monitoring, Testing and Investigation

(l) OC 12: System Recovery

(m) OC 13: Work Safety

OC 1.2. Operating Principles

The System Operator shall prepare an operating plan prior to bringing scheduled generation on-line for the next day to meet the forecasted load demand. Procedures for implementation of the plan are described in the Scheduling and Dispatch Code.

The operating plan shall include the following operating principles:

(a) Adequate capability for Voltage regulation and Frequency Control must be ensured in the System at all times under Normal operating conditions;

(b) Proper Outage co-ordination and assessment of System Security impacts should be carried out prior to real-time Operations;

(c) Transmission congestion management and contingency event management must be provided in accordance with the Operating Criteria and principles laid down in the Operation Sub-Code (OC 6) of this sub-code.

(d) Adequate reactive reserve management and voltage regulation must be carried to meet the operating standards stated in OC.5.4 and OC.5.5 of this Code.

(e) Adequate Ancillary Services must be ensured prior to real-time operations.

(f) Provision of adequate protection and control based on the requirements laid down in Protection and Control Code must be provided by the Users.

(g) Functioning of dual communication systems during System Operation and Dispatch must be ensured by the System Operator and Code Participants using devices as described in OC.9.

(h) Provision of pre-operational plans regarding Black Start Facilities and pre-tested system restoration plan under Black Out conditions must be ensured by the System Operator, via restoration plan revisions as given in OC.12.

(i) Minimization of power imbalances at all times must be ensured by the System Operator.

(j) The System Operator must ensure that all the thermal loadings, system voltages, system frequency, system stability (both steady-state and transient) are well within established limits as provided in the OC 5 and 6, of this sub-code.

(k) The HVAC system shall at all times be operated in harmony with HVDC in such a way as to achieve the best overall performance of the integrated HVAC and HVDC Transmission System.

(l) The System Operator shall periodically carry out necessary Transmission System studies, simulations and tests (e.g. fast fault current injection, fault ride through capability, power oscillations damping control etc.) for expected system event scenarios (e.g. major outages of equipment, HVDC pole(s) failure etc.) that could lead to transient instability (unsatisfactory system dynamic performance and loss of power angle stability), voltage instability, small signal instability, and/or lack of power system oscillation damping.

(m) The System Operator shall maintain and be able and ready to implement, when required, standard operating procedures and Defense Plans (including manual control actions, cross-trip schemes, Stability Control Systems, Remedial Action Schemes) designed to mitigate the extent of disturbance resulting from a system event.

OC 2. **OPERATIONAL DEMAND FORECASTS**

OC 2.1. **Introduction**

OC 2.1.1. OC.2 specifies the process and information requirements for preparing Operational Demand Forecasts by the SO for different Operational Planning Horizons to match supply with demand on the Transmission System. Demand Forecast will include forecast for Active and Reactive Power.

OC 2.1.2. Demand Forecasts will be conducted on the four (4) Operational Planning Horizons:

(a) Pre-Operational Phase (Year 1 and Year 2);

(b) Operational Phase, (3-Month ahead of the Schedule Day)

(c) Control Phase, (day ahead of the Schedule Day and real-time operation); and

(d) Post Control Phase (the day following the Schedule Day);

OC 2.1.3. OC2 also deals with the provision of data on Demand Management by the Users in the four (4) Operational Planning Horizons as listed in (OC 2.1.2) above;

OC 2.1.4. SO will develop demand forecasts by taking into account the information/forecasts supplied to it by the Users and by considering any other external factors as described in OC.2.5.1

OC 2.1.5. In this OC2, Year 0 means the current calendar year, Year 1 means the next calendar year, and Year 2 means the calendar year following Year 1 and so on.

OC 2.1.6. References in OC2 to data being supplied on an hourly basis refer to these being supplied for each period of 60 minutes ending on the hour (or any sub-hourly period that may be specified by the SO with approval of NEPRA in the future).

OC 2.1.7. Reactive Power Demand shall be determined on Connection Point and shall include the series reactive losses of the User's System but exclude any network susceptance and any reactive compensation on that System. The SO shall obtain the lumped network susceptance values and details of the reactive compensation from the data supplied by the User pursuant to the Planning Code.

OC 2.1.8. The timelines and data resolutions specified in this OC.2 may be modified by the SO from time to time and notified to the Users.

OC 2.2. **Objectives**

OC 2.2.1. The objectives of OC2 are to:

(a) Ensure the provision of data to the SO by Users for all Operational Programming Horizons by the specified time and in the requisite format; and

(b) Describe the factors that the SO will take into account when preparing Demand Forecasts.

OC 2.3. **Scope**

OC2 applies to the SO and the Users which in this OC2 means:

(a) Distribution Companies;

(b) Suppliers;

(c) Bulk Power Consumers (BPCs);

(d) Transmission Connected Consumers;

(e) Interconnectors; and

(f) Energy Storage Units in respect of their demand.

OC 2.4. **Data Required by the SO in the Pre-Operational Phase**

OC 2.4.1. No later than 1st of March each Year, the SO shall notify to each User In Writing (or by publishing on its web site) the following (for Years 1 and Year 2):

(a) the date and time of the SO's expected annual peak Demand at annual maximum Demand conditions; and

(b) the date and time of the SO's expected annual minimum Demand at average conditions.

OC 2.4.2. For Pre-Operational Phase, the Users shall provide to the SO the following data in writing by end-March of Year 0:

(a) profiles of the User's anticipated hourly Demand summed over all Connection Points and for each Connection Point (or as otherwise specified by the SO e.g. district wise), for defined categories of day types as mentioned in OC2.4.1;

(b) profiles of the User's anticipated hourly Demand summed over all Connection Points and for each Connection Point (or as otherwise specified by the SO e.g. district wise), for the day of that User's own maximum/minimum Demand;

(c) annual Active Energy requirements for Average Conditions segregated into different usage categories such as, residential, commercial, industrial, agriculture, etc., wherever practicable, (summed over all Connection Points);

(d) For Year 1, profiles of the anticipated Energy and Peak Demand on monthly basis, summed over all Connection Points and for each Connection Point (or any other basis specified by SO e.g. district wise);

(e) Users shall supply MW profiles of the amount and duration of anticipated Demand Control which may result in a Demand change of 10MW or more on hourly and Connection Point basis;

(f) For DISCOs, typical MW profiles for the operation, or Availability as appropriate, of Embedded Generation within their respective systems, where the total Registered Capacity of these Generating units on a single Site exceeds ten (10) MW for defined categories of the day type as determined by the SO (and for all other profiles as well). The method for submitting MW schedules and/or Availability shall be agreed between the SO and the DISCOs, such agreement not to be unreasonably withheld;

(g) Notwithstanding OC.2.4.2(f), if the SO considers the Site to be critical for System Operation, it may request the Users MW profiles for the operation, or Availability as appropriate, of Embedded Generation where the total Registered Capacity of Generating units on a single Site exceeds five (5) MW, for defined categories of day type as determined by the SO. The method for submitting MW schedules and/or Availability shall be agreed between the SO and the Users, such agreement not to be unreasonably withheld.

(h) While consolidating the demand forecasts provided by individual Users, the SO will also take into account estimated Transmission System losses, based on historical and other relevant factors.

OC 2.5. **Data Required by The SO for the Operational Phase**

OC 2.5.1. Three (3) months ahead of the real-time, the Users shall provide to the SO the following information in writing by 1000 hours on first working day of each month (the three (3) month period being a rolling period):

(a) profiles of the anticipated daily Energy and Peak Demand, summed over all Connection Points and for each Connection Point (or any other basis specified by the SO e.g. district wise).

(b) MW profiles of the amount and duration of their proposed daily Demand Management which may result in a demand change of ten (10) MW or more on any Connection Point.

(c) Daily MW average of the Embedded Generators within their system, with Registered Capacity of ten (10) MW or more.

OC 2.5.2. By 1000 hours each Wednesday, the Users shall provide to the SO the following information for the next seven (7) days ahead of the Schedule Day:

(a) Profiles of the anticipated Energy and Peak Demand on hourly basis, summed over all Connection Points and for each Connection Point basis (or any other basis specified by SO e.g. district wise).

(b) MW profiles of the amount and duration of their proposed hourly Demand Management which may result in a demand change of ten (10) MW or more, on any Connection Point.

(c) Hourly MW profile of the Embedded Generators within their system, with Registered Capacity of ten (10) MW or more.

OC 2.6. **Development of Operational Demand Forecast by SO**

OC 2.6.1. The SO shall develop Demand forecast based on the information/forecasts provided by Users pursuant to OC2.5, and by also considering the following additional factors, if necessary:

(a) Historical Demand data;

(b) Weather forecasts and the current and historical weather conditions;

(c) The incidence of major events or activities which are known to the SO in advance;

(d) Transmission System losses and auxiliary consumption;

(e) Embedded Generation;

(f) Any other relevant Socioeconomic development in the country;

(g) Demand Management of ten (10) MW or proposed to be exercised by the User and of which the SO has been informed; and

(h) Any other information required by SO from the Users.

OC 2.6.2. The SO will develop Demand Forecast using appropriate forecast methodology/tool, by incorporating the demand forecast supplied by Users and further taking into account factors specified in OC2.6.1.

OC 2.6.3. For all Operational Planning Horizons, the Users shall inform the SO of any changes to the information supplied as soon as this information is available. This information will be provided in writing, or as otherwise agreed between the Users and the SO, such agreement not to be unreasonably withheld.

OC 2.6.4. The forecasts developed under OC 2.6 will be used during Operational Planning, Scheduling and Dispatch and system studies/simulations.

OC 2.7. **Post Control Phase**

The Users shall provide the following data to the SO in writing (or by such electronic data transmission facilities as have been agreed with the SO) by 0200 hours each day in respect of Active Power data and Reactive Power data for the previous Schedule Day:

(a) MW profiles of the amount and duration of Demand Management achieved from the use of Demand Management on hourly and Connection Point basis; and

(b) details of hourly Active Power output and Reactive Power produced or absorbed by Embedded Generation, with a single Site with Registered Capacity in excess of ten (10) MW.

OC 2.8. **Accuracy of Demand Forecasts provided by Users to the SO**

OC 2.8.1. The SO will assess the accuracy of Users' demand forecasts against actual demand over the relevant Planning Horizon.

OC 2.8.2. The performance of the forecasts provided should be below the MAPE values provided for different Planning Horizons in Table OC.2-1.

Table: OC.2-1: Performance Requirements for Demand Forecasts

Horizon	Resolution	Evaluation Metric	Evaluation Metric Range	Probability Metric and Measurement horizon	Remarks
Week Ahead (OC	Hourly	Daily MAPE	3%	P95 at monthly basis	Daily MAPE to be less than 3% at least 95% of

Horizon	Resolution	Evaluation Metric	Evaluation Metric Range	Probability Metric and Measurement horizon	Remarks
2.5.2)					the days in a month
Year Ahead (OC 2.4.2 iv)	Monthly	Annual MAPE of the monthly energy values	3%	-	Error between the forecasted and actual energy consumption averaged over 12 months be within 3% range

OC 2.8.3. A User whose forecasts repeatedly fail to meet the MAPE targets specified in Table OC.2-1 shall be liable to appropriate sanctions or penalties (or both), as per the Fine Rules approved by NEPRA.

OC 3. **DEMAND MANAGEMENT**

OC 3.1. **Introduction**

OC 3.1.1. Operation Code No. 3 (OC 3) specifies the provisions that are to be used by the SO to manage demand on the Transmission System using Demand Management provided by Demand Side Units due to:

(a) available Generation and imports from Interconnectors being insufficient to meet Demand;

(b) insufficient Operating Reserve; or

(c) breakdown or operating problems resulting in System Frequency excursions, Voltage variations or Thermal Overloading on any part of the Transmission System.

OC 3.1.2. Demand Management may be achieved by any of the following:

(a) Demand Side Unit Response instructed by the SO;

(b) Demand Side Unit Control instructed by the SO;

(c) Demand Side Unit restoration instructed by the SO;

(d) Automatic low Frequency Demand Disconnection;

(e) Automatic low Voltage Demand Disconnection;

(f) Automatic Frequency Restoration; or

(g) Emergency Manual Disconnection by SO etc.

OC 3.2. **Objective**

OC 3.2.1. The objective of OC 3 is to provide rules and procedures to enable the SO to achieve Demand Management that will relieve planned and unforeseen operating problems on the National Grid.

OC 3.3. **Scope**

OC3 applies to the SO and the relevant Users including:

(a) DISCOs;

(b) TNOs;

(c) Suppliers;

(d) BPCs;

(e) Transmission Connected Consumers; and

(f) Interconnectors with respect to their demand.

OC 3.4. **Explanation**

OC 3.4.1. Demand Control is exercised in contingency and emergency situations whereby the SO can instruct any User to reduce its Demand.

OC 3.4.2. Demand Response is exercised on a voluntary basis with prior contractual arrangements with those Users who have willingly agreed to have their Demand changed by SO for the purposes of improving system performance.

OC 3.4.3. In addition, the SO can also manually cut off supply to the User facility or part thereof from any disconnection point, without prior notice, in extreme emergencies.

OC 3.4.4. The procedures set out in OC.12 includes a system of Alerts, issued to Users, to give advance notice of Demand Control that may be required by the SO under this OC3.

OC 3.4.5. Demand Control shall not, so far as be possible, be exercised in respect of Priority Customers.

OC 3.4.6. Demand Control shall be exercised fairly and equitably in respect of all Users affected by Demand Control, on best effort basis.

OC 3.4.7. Demand Control is exercised through operation of the Distribution System or the Transmission System. Demand Control relates to the physical organization of the total System, and not to any contractual arrangements that may exist. Where Demand Control is needed in a particular area, the SO would not know which Supplier to contact and (even if it was to) the resulting Demand Control implemented, because of the diversity of contracts, may not produce the required result.

OC 3.4.8. Therefore, in most instances of Demand Control, Demand Control will be exercisable by the DNO/TNO. Suppliers/BPCs should note therefore, that although implementation of Demand Control in respect of their Customers may not be exercisable by them, their Customers may be affected by Demand Control. Suppliers/BPCs shall coordinate with their respective DNO/TNOs to prepare Demand Management plans. However, DNO/TNOs shall ensure the implementation of Demand Control within its Service Territory as instructed by SO.

OC 3.5. **Not Used**

OC 3.6. **Procedure for the Implementation of Planned Demand Management on the Instructions of System Operator**

OC 3.6.1. Where due to a shortage of generation capacity or any other reason, exercising of Demand Management becomes imminent; the SO will Alert the Users in accordance with OC 12.

OC 3.6.2. During Demand Management, Generation Dispatch shall cease and shall not be re-implemented until the SO has determined that it is safe to do so.

OC 3.6.3. The System Operator shall provide as much advance warning as practicable of any unforeseen circumstances which are likely to result in Demand Management procedures being implemented. This shall ensure that all the Users shall be in a state of readiness to implement their planned Demand Management procedures.

OC 3.6.4. All the Users participating in the Demand Response are required to be able to respond at a short notice to the System Operator's instructions to implement Demand Response.

OC 3.6.5. The SO shall initiate the Demand Control if Demand Response is not enough to compensate for the shortage. The total amount of Demand Control required shall be distributed among all relevant Users considering each User's demand in real-time and System conditions on pro rata basis. The instruction for Demand Control could be given in any suitable form, including:

(a) fixed quantum of load to be shed;

(b) quota allocation for power drawn from System;

(c) maintaining load on a network equipment below specified limit;

(d) maintaining voltage on a specified node above a certain threshold.

OC 3.6.6. Where reasonable notice time for Demand Control is available, the SO will instruct the DNO/TNOs to implement Demand Control within their respective Service Territories, and Demand Management schedules (prepared by coordination among DNO/TNOs and Suppliers/BPCs) will be implemented. The SO and Users shall co-operate with each other so as to enable the implementation of Demand Control as per requirements of SO. The SO may also, if possible, specify the expected duration of Demand Control required, for information.

OC 3.6.7. Where the requirement for Demand Control arises at a short notice, it may be necessary for practical reasons to implement Demand Control immediately, outside the planned Demand Management schedule. The Users will each adhere to the specified procedures (and will co-operate in forming such procedures) to provide that Demand Control can be exercised rapidly when required, in accordance with the SO's instructions.

OC 3.6.8. In the event that Demand Control being exercised under OC 3.6.7 is expected to be sustained, then the DNO/TNO will arrange to gradually shift towards planned Demand Management schedule, as soon as is practicable.

OC 3.6.9. The planned Demand Management schedule provides for disconnection and reconnection of defined blocks of demand as per predefined time schedules. The Users shall comply with the instructions issued by the SO and shall not reconnect Demand without the SO's instructions.

OC 3.6.10. Users shall provide full details of their Demand Management plans to the System Operator on an annual basis in advance (if required by SO). The SO may instruct certain modifications of the Demand Management schedule proposed by a User.

OC 3.6.11. After restoration of the National Grid to Normal State, Users shall supply information to the System Operator, which shall include the magnitude, date and time, location, cause and the relevant details of the Demand Management methods employed by them respectively.

OC 3.6.12. Users shall also provide online facilities to SO for monitoring Demand Control/Response implementation in real-time, as further detailed in OC 9.

OC 3.7. **Automatic Low Frequency Demand Disconnection**

OC 3.7.1. All disconnection points (11kV and above) or otherwise as identified by SO shall be provided with low frequency disconnection facilities. This is necessary to ensure that in the event of a large Generating Unit failure, there is a staged and phased Demand Disconnection to ensure System Stability.

OC 3.7.2. Low Frequency Disconnection scheme should, as far as practicable, ensure that supply of any Embedded Generation is not affected.

OC 3.7.3. Demand of Generating Units which is required to enable the start-up of Generating Units, as far as possible, should not be subject to Automatic Low Frequency Disconnection.

OC 3.7.4. Once an Automatic Low Frequency Demand Disconnection has taken place, a User shall not reconnect its Demand until instructed to do so by the SO, or otherwise in accordance with agreed procedures.

OC 3.7.5. The Users which are subject to automatic low Frequency Disconnection will be split into discrete MW blocks. The number, location, size and the associated low Frequency settings of these blocks, will be as specified by the SO by week 28 in each calendar year or as and when required by SO following discussion with the Users. The distribution of the blocks will be such as to exercise Demand Control as uniformly as may be practicable across all Connection Points.

OC 3.7.6. In case of a User, it is not necessary for it to provide Automatic Low Frequency Disconnection under OC3.7 if it is providing low Frequency Disconnection at a higher level of Frequency as an Ancillary Service.

OC 3.7.7. Users shall be capable of Automatic Low Frequency Disconnection between 47 – 50 Hz.

OC 3.7.8. The Automatic Low Frequency Disconnection scheme for a User shall be capable of disconnecting Demand in Phases for a range of operational frequencies. The specific performance requirements of the scheme shall be specified by the SO.

OC 3.7.9. The automatic low Frequency Disconnection scheme shall allow for operation from a nominal AC input to be specified by the SO, and shall meet the following functional capabilities:

(a) Frequency range: at least between 47-50 Hz, adjustable in steps of 0.05 Hz;

(b) Operating time: no more than 200 ms after triggering the Frequency set-point;

(c) Voltage lock-out: blocking of the functional capability shall be possible when the voltage is within a range of 20 to 90 % of the nominal voltage; and

(d) Provide the direction of active power flow at the point of disconnection.

(e) Rate of Change of Frequency shall be adjustable anywhere within in the range of 0.1 Hz/sec to 2.5 Hz/sec.

The AC voltage supply used in providing these automatic low Frequency Disconnection functional capabilities, shall be measured at the Connection Point.

OC 3.8. **Automatic Frequency Restoration**

OC 3.8.1. The Users will make necessary arrangements to enable automatic Frequency restoration of Demand that is subject to automatic low Frequency Demand Disconnection. The SO shall specify the Frequency settings on blocks of Demand subject to automatic Frequency restoration.

OC 3.8.2. Where conditions following automatic low Frequency Demand Disconnection do not permit restoration of a large proportion of the total Demand Disconnected within a reasonable time period, the SO may instruct the Users to implement additional Demand Control 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. If the requirement for Demand Control is expected to continue for a sustained period of time, then the SO will initiate the implementation of the planned demand management schedule in accordance with OC 3.6.

OC 3.8.3. Once the System Frequency has recovered, the Users will abide by the instructions of the SO with regard to reconnection, and/or shall implement agreed procedures for Demand reconnection, without undue delay.

OC 3.9. **Voltage Demand Disconnection**

OC 3.9.1. The SO may from time to time determine the requirement for Automatic Low Voltage Disconnection of Demand, in order to limit the consequences of the loss of a Generating Unit(s), or any other event on the System, which otherwise would result in part of the total System Voltages to become outside the levels specified in OC 5.5.7

OC 3.9.2. The SO may exercise the required Automatic Low Voltage Demand Disconnection (ALVDD) at the level of the Transmission System. However, depending on the extent of ALVDD required, and in order not to disconnect more Demand than reasonably required in response to a specific incident or set of circumstances, it may be preferable that ALVDD is carried out at the lower voltage levels of the Users.

OC 3.9.3. As and when required by the SO, the Users will cooperate with the SO in the design and implementation of ALVDD at locations on the Users, where the requirement is indicated, in accordance with OC 3.9.2. The SO will retain full control over the enabling/disabling of the ALVDD, and the Voltage settings at which ALVDD will be initiated in each circumstance.

OC 3.9.4. In general, the settings will be specified by the SO by week 28 in every three calendar years (but not limited to) following discussion with the Users, but the specification of settings may be altered by the SO at other times to address specific circumstances pertaining at that time. The Users shall respond to any change in specification by altering the settings without undue delay.

OC 3.9.5. The SO will specify the functional capabilities for low voltage demand disconnection, in co-ordination with Users, on a site specific basis. It will include as a minimum: monitoring voltage at all three phases; and blocking of the relays operation based on direction of either Active Power or Reactive Power flow.

OC 3.9.6. Low voltage demand disconnection shall be implemented automatically or manually.

OC 3.9.7. The SO may specify the requirement for on-load tap changer blocking. Users will be advised as necessary, on a case-by-case basis, taking into consideration the site-specific requirements.

OC 3.10. **Emergency Disconnection**

OC 3.10.1. In the event of a System Emergency, irrespective of the frequency, the System Operator shall have the right of involuntarily disconnection (manually or automatically) of any facility of any User when it determines that the Transmission System might or could become incapable of providing the required services as mandated in its license. Users shall provide appropriate facilities to the SO for fast disconnection of load as per System requirements such as Automatic Demand Management System (ADMS).

OC 3.10.2. Quantum of Demand and specific location of Demand reduction shall be at the discretion of the System Operator depending on the conditions prevailing at that time. This action may be necessary to protect life, limit plant damage and to maintain power supply to the majority of Consumers. However, the System Operator shall endeavor to carry out Demand Management fairly.

OC 3.10.3. Users shall comply with the System Operator instructions when restoring supplies in their respective systems.

OC 3.10.4. Each User shall provide the System Operator in writing, by week 28 in each calendar year, the information contained in Appendix A of this sub-code in respect of the next following calendar year, on each Transmission Connection Point basis. However, SO, if necessary, shall advise modifications in the provided information to make it practicable as per prevailing system conditions and requirements.

EMERGENCY MANUAL DEMAND REDUCTION/DISCONNECTION SUMMARY SHEET

Name of Company/ Code Participant/ Transmission Connected Consumer:

Peak Demand [Year] MW

(132 & 66kV Radial Lines, 132/11kV & 66/11kV Transformers)

Transmission Connection Point	**Peak (MW)**	**% of Load Demand Reduction or Disconnection *with respect to Peak MW at the Transmission Connection Point (%)***

Note: Data to be provided annually by week 28 to cover the following calendar year.

OC 4. OPERATIONAL PLANNING

OC 4.1. Introduction

In order to enable the SO to fulfill its obligations for reliable operation of the Transmission System, the Generation and Transmission facilities must be kept in perfect working conditions by carrying out their necessary upkeep and maintenance in a timely, coordinated, and orderly fashion. This requires proper planning and coordination of maintenance activities among the Transmission Network Operators, Generators, DISCOs, BPCs and Interconnectors. The mechanisms by which this is to be achieved are formalized in this Operational Planning Code (OC4).

OC 4.2. Objective

OC 4.2.1. The primary objective of OC 4 is to ensure the development and implementation of a coordinated Generation and Transmission Outage Program (G&TOP), that is consistent with the requirements for the secure and economic operation of the Transmission System and also duly considers the maintenance requirements of relevant Users.

OC 4.2.2. In order to achieve this objective, the OC4 defines:

(a) the procedure for formal notification of proposed Outages by relevant Users to the SO;

(b) the process the SO will use to review and develop the long, medium and short term Outage Programs, in consultation with the relevant Users.

(c) the procedure for formal notification by Users of:

(i) a decision to cancel a major Outage of a Generating Unit/Equipment;
(ii) the findings during or following a major Outage of a Generating Unit/Equipment;
(iii) an unexpected and unplanned failure of a Generating Unit/Equipment.

OC 4.2.3. In respect of Generators/Interconnectors, the OC 4 shall apply to all proposed Outages that may affect the ability of a Generator/Interconnector to achieve either its full Registered Capacity appropriate to each Registered Fuel, or Interconnector Registered Capacity, as the case maybe, in accordance with its Registered Operating Characteristics.

OC 4.2.4. Generators/Interconnectors are also mandated to inform the SO of any other proposed maintenance of their Units or any associated Plant or Apparatus, where such maintenance will affect the availability of their obligation to provide System Services.

OC 4.2.5. In this OC4, a reference to Year 0 shall mean the current calendar year, Year 1 shall mean the next calendar year, Year 2 shall mean the calendar year after Year 1, and so forth.

OC 4.3. Scope

The scope of this Code applies to the SO and the following Users:

(a) Generators;

(b) Transmission Network Operators;

(c) DISCOs;

(d) Transmission Connected Consumers;

(e) Interconnectors; and

(f) Small/Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO).

OC 4.4. **Planning of Generation Outages**

OC 4.4.1. The Outage planning process in respect of a Generating Unit shall commence not later than three (3) years prior to the scheduled Operational Date or from the date of the relevant Agreement(s), whichever is later. The process shall culminate in development of the following three Programs scheduled over the time scales indicated as below:

(a) Committed Generation Outage Program, covering real time up to end of Year 1;

(b) Provisional Generation Outage Program, covering Year 2; and

(c) Indicative Generation Outage Program, covering Year 3.

OC 4.4.2. The closer the Generation Outage Program is to real-time operations, the more accurate it must be to ensure that there is adequate generation to match demand. As real-time approaches, there shall be regular exchange of information between each Generator and the System Operator, to update the Generation Outage Program with the latest availabilities.

OC 4.5. **Procedure**

OC 4.5.1. By the end of March Year 0, Generators shall provide to the SO (in the forms notified by the SO from time to time), for each of their Generating Units, the following details of proposed Outages and estimates of probabilities of Forced Outages[1] for Years 1 to 3, for inclusion in the Committed, Provisional, and Indicative Generation Outage Programs, as defined in (OC 4.4.1) above:

(a) identity of the Generating Unit(s) concerned;

(b) MW unavailable (and MW that will still be available, if any, notwithstanding the Outage);

(c) expected duration of the Outage;

(d) preferred start date and start time or range of start dates and start times;

(e) any other information required by the SO.

OC 4.5.2. In rolling over the Generation Outage Program from one year to the next, for every year, the procedure set out below is to be followed:

[1] Force outage probability of existing Generators shall normally be based on historical data for each Generating Unit regarding faulted events and time-to-repair as further elaborated in the relevant operating procedures.

(a) submissions by the Generator for Year 2 should reflect the current Indicative Generation Outage Program; and

(b) submissions by the Generator for Year 1 should reflect the current Provisional Generation Outage Program.

(except, in any such case, to the extent that the Generator is reasonably responding to changed circumstances and changes which, in the context of the Generation Outage Program, are minimal in their effect on the operation of the National Grid).

OC 4.5.3. By 1st September Year 0, VRE Generators shall provide to the SO (or revise any such information previously given) the forecast of estimated net output of the Wind/ Solar PV/CSP Power Plant in MWh which it is likely to generate for each Month of Years 1, 2 and 3.

OC 4.5.4. By the end of September Year 0, the SO shall conduct Reliability analysis of the Transmission System for the operational planning horizon in light of the proposed Outages, and calculate the [monthly] peak Generation Capacity required from Generating Units for the various planning periods (Year 0, 1, 2, etc.) by considering the following factors:

(a) Forecasted Demand;

(b) User Demand Control;

(c) Operating Reserve as set by the SO;

(d) Estimated hydrology (reservoir levels, water flows etc.);

(e) Ancillary Services requirements;

(f) Transmission System and Distribution System constraints; and

(g) Transmission System and Distribution System Outages to ensure that, in general, these have the least restraint on Generating Unit Outages.

(h) Any other relevant factor.

OC 4.5.5. During this period the SO may, as appropriate, contact any User which has supplied information to seek clarification on its information received or any other relevant information as is reasonable. The SO shall also notify to Generators any concerns for their submitted Programs and try to settle these through mutual discussion. If these cannot be resolved mutually, the Generator must provide the SO with such evidence as the SO may reasonably require to substantiate that the proposed Outages cannot be modified. If the Generator fails to establish to the reasonable satisfaction of the SO that the proposed Outage is inflexible, the SO will modify the Outage as per its requirements. All communication shall be recorded for future reference.

OC 4.5.6. The process of consultation and preparation of the Generation Outage Program shall be concluded by Oct 31st of each year and published on the SO website.

OC 4.5.7. In proposing Outages, and in relation to all other matters under OC 4, the Generators/Interconnectors must act reasonably and in good faith. Without limitation to such obligation, each Generator/Interconnector shall act in accordance with Prudent Industry Practice in planning their Outages, so as to avoid a situation arising in which a Generator/Interconnector is obliged to schedule an Outage at short notice by reason of obligations imposed on it by statute, as a consequence of the Generator/Interconnector not having planned in accordance with Prudent Industry Practice, for example, by not having planned sufficiently in advance its Outages for any statutory time limit.

OC 4.5.8. Not Used

OC 4.5.9. Not Used

OC 4.6. **Changes to the Committed Outage Program within the Implementation Year (Year 0)**

OC 4.6.1. A request for a change to an Outage included in the Committed Generation Outage Program may be initiated either by the SO or by a Generator/Interconnector at any time.

OC 4.6.2. **Request initiated by the SO**

(a) The SO may at any time request a Generator/Interconnector to change the timing or duration of any Outage in the Committed Generation Outage Program where, in the SO's opinion (were such Outage not to be deferred):

(i) the statutory or regulatory obligations could not be met; or

(ii) there would be insufficient Generation Capacity to meet Forecasted Demand and the Operating Reserve.

(b) The SO may require the Generator/Interconnector to continue to defer such Outages for as long as the above situation persists. If a Generator/Interconnector responds by agreeing to the request, the Committed Generation Outage Program shall be deemed to have been amended accordingly.

(c) If a Generator/Interconnector declines the request of the SO, then the SO may discuss with the Generator/Interconnector to resolve the issue. If a mutual resolution is not reached, the Generator must provide the SO with such evidence as the SO may reasonably require to substantiate that Outage cannot be modified. If the Generator/Interconnector fails to establish to the reasonable satisfaction of the SO that the proposed modification is not possible, the Outage shall stand modified as per SO requirements.

OC 4.6.3. **Outage Change Initiated by a Generator/Interconnector**

(a) Generators/Interconnector may at any time request the SO for a change in the timing or duration of its Outage in the Committed Generation Outage Program. Such requests should normally be initiated by giving not less than seven (7) days prior notice before the earliest start date of the Outage.

(b) Such a request must also include a valid reason for the proposed change in the Outage schedule.

(c) The SO shall evaluate whether the change is likely to have a detrimental effect on Capacity Adequacy or on the secure operation of the Transmission System. This shall be done within a reasonable time frame, taking into consideration the extent of the change and the timing of the Outage.

(d) Where the request is not likely to have a detrimental effect on Capacity Adequacy or the secure operation of the Transmission System then the SO shall amend the Committed Generation Outage Program accordingly. The Generator/Interconnector shall be advised by the SO that the change has been accepted.

(e) Where the Outage change is likely to have a detrimental effect on Capacity Adequacy or requirements for the secure operation of the Transmission System, then the SO shall not amend the Committed Generation Outage Program. The Generator/Interconnector and the SO may discuss and agree on a modification which may meet the requirements of the Generator/Interconnector, and not have an unacceptable effect on Capacity Adequacy or requirements for secure operation of the Transmission System. In the event that the Generator/Interconnector wishes to avail of an agreed modification, it shall submit a change request in accordance with OC 4.6.3 (a).

(f) Where the Generator/Interconnector has been notified that the change to the Committed Generation Outage Program has not been accepted, but the Generator/Interconnector still avails the Outage, it shall be considered as non-compliance as per OC 11.

OC 4.7. **Short Term Planned Maintenance (STPM) Outage**

OC 4.7.1. A Generator/Interconnector may request the SO at any time during Year 0, by giving not less than seven (7) days prior notice before the earliest start date, for a Short Term Planned Maintenance (STPM) Outage. The request must contain the following information:

(a) identity of the Generating Unit(s) concerned;

(b) MW on Outage (and MW which would still be available, if any, notwithstanding the Outage);

(c) required duration of the Outage (which must not exceed seventy-two (72) hours); and

(d) preferred start date and start time or range of start dates and start times.

OC 4.7.2. On receipt of such a request, the SO shall consider the request and shall, after discussing the position with the Generator/Interconnector, reply normally within three (3) working days in writing indicating:

(a) acceptance of the request, confirming the requested start time and duration of the STPM Outage;

(b) proposals for the advancement or deferment of the requested STPM Outage, indicating alternative start time and duration; or

(c) rejection of the request.

OC 4.7.3. If the SO accepts the request, the STPM Outage, if taken, must be taken by the Generator/Interconnector in accordance with the approved request. If the SO has indicated an alternative start time and/or duration, the SO and the Generator/Interconnector must discuss the alternative and any other options which may arise during the discussion. If agreement is reached, then the Outage, if taken, must be taken by the Generator/Interconnector in accordance with the agreement. If the request is refused by the SO based on grounds established in OC 4.6.2 (a) or if agreement is not reached, then the Generator/Interconnector will not take the Outage.

OC 4.7.4. Not Used

OC 4.7.5. Not Used

OC 4.7.6. Where an STPM Outage is scheduled pursuant to OC 4.7, the SO shall confirm the details, normally within one (1) working day after the approval of the STPM Outage by the SO. Such notice shall contain the following information:

(a) the identity of the Generating Unit(s) concerned;

(b) MW on Outage (and MW which would still be available, if any, notwithstanding the Outage);

(c) duration of the Outage; and

(d) the start date and start time of the Outage.

OC 4.8. **Release of Generating Units for Outages**

OC 4.8.1. The Generators/Interconnectors may only undertake Planned Outages with the SO agreement pursuant to the provisions of this OC 4.

OC 4.8.2. In real time operation, Generating Units must not be withdrawn for an Outage without express formal permission of the SO for such release according to the procedures set out in OC 4.6 and OC 4.7.

OC 4.8.3. The SO’s express formal permission shall specify:

(a) the identity of the Generating Unit and MW on Outage (and MW which would still be Available, if any, notwithstanding the Outage);

(b) the duration of the Outage; and

(c) the start date and start time of the Outage.

OC 4.8.4. The SO may withhold its permission for the release of a Generating Unit for a Planned Outage under Committed Generation Outage Plan or STPM, in accordance with OC 4.6.2.

OC 4.8.5. **Notified Unplanned Outage**

OC 4.8.5.1. If Generator/Interconnector must require an Unplanned Outage which cannot reasonably be requested to the SO as per OC 4.7, it must provide notice to the SO as early as possible. Such notice must include an identification of the Generating Unit, the expected start date and start time and duration of the Unplanned Outage, and the nature of the Outage together with the MW on Outage (that is, MW which will not be available as a result of the Outage and that which will still be available, if any). The SO will acknowledge such notice as soon as reasonably possible after the notice is received by the SO.

OC 4.8.5.2. The SO may request the Generator/Interconnector to advance or defer the Outage. If the Generator agrees to such a request, the Generator shall send the SO a written notice confirming this agreement. The SO will acknowledge this notice. The Generator/Interconnector must then take the Outage in accordance with this agreement.

OC 4.8.5.3. A Generator/Interconnector shall use all reasonable endeavors to ensure that, following an Unplanned Outage, the Generating Unit/Interconnector is repaired and restored to its full level of Availability as soon as possible and in accordance with Prudent Industry Practice.

OC 4.8.5.4. However, the SO shall have the right to Investigate whether the Outage was unavoidable or could not have been planned in time.

OC 4.9. **Forced Outages**

OC 4.9.1. In the event that a Generator/Interconnector suffers a Forced Outage, the Generator/Interconnector shall inform the SO immediately.

OC 4.9.2. As soon as possible after the commencement of the Outage, the Generator/Interconnector shall also inform the SO of the cause of the Outage and the Generator/Interconnector's best estimate of the date and time by which the Generating Unit is likely to be repaired and restored to its full level of Availability. If the Generator is unable for any reason to provide this information, the Generator/Interconnector shall not later than twenty-four (24) hours after the commencement of the Forced Outage, provide the SO such information as is then known to the Generator/Interconnector regarding the date and time of return from such Outage and shall provide such updates thereafter as the SO may reasonably require.

OC 4.9.3. In such an event, the SO shall have the right to inspect the Generating Unit and all relevant records on any working day and at a reasonable time. The Generator shall fully cooperate with the SO during any such inspection.

OC 4.9.4. A Generator shall use all reasonable endeavors to ensure that, following a Forced Outage, the Generating Unit is repaired and restored to its full level of Availability as soon as possible and in accordance with Good Industry Practice.

OC 4.10. **Return to Service and Overruns**

OC 4.10.1. For a Planned Outage, as far in advance as reasonably possible before the expiry of the Outage period, the Generator/Interconnector must notify the SO either that it is returning to service earlier than expected, or at the time and date expected, or later than expected and if, upon return, it is expected to be fully available.

OC 4.10.2. Where a Generating Unit is not expected to be fully available upon its return to service, the Generator shall state the MW level at which the Generating Unit is expected to be available. In the case of a Generating Unit which is capable of firing both on gas and on oil, the Availability must be stated for each fuel.

OC 4.10.3. In the case of a return from a Planned Outage later than expected, the notice of return to service shall state the reason(s) for the delay in the return of the

Generator/Interconnector to service and a best estimate of the date and time at which it will return to service.

OC 4.10.4. Not Used

OC 4.10.5. A Generator/Interconnector must use all reasonable endeavors to ensure that, in respect of each Planned Outage, the Outage schedule as included in the Committed Generation Outage Program (or as moved in accordance with the provisions of this section) is followed.

OC 4.10.6. Before returning from any Outage other than a Planned Outage, a Generator/Interconnector must inform the SO, as far in advance as reasonably possible that it is returning to service. The Generator/Interconnector must, in addition, give an Availability Notice in accordance with the provisions of the SDC 1 on the day prior to the Schedule Day on which the Generator/Interconnector is to return to service.

OC 4.10.7. If at any time during an Outage, the Generator/Interconnector becomes aware that it will not have been maintained, repaired or restored to be available by the expiry of the period specified for the duration of the Outage in the Committed Generation Outage Program or as otherwise notified in the case of Outages other than Planned Outages, the Generator/Interconnector shall notify the SO immediately in writing stating the reason(s) for the delay and a best estimate of the date and time by which the Generating/Interconnector will actually have been maintained, repaired, or restored to be available in accordance with the provisions of the SDC 1.

OC 4.11. **Planning of Transmission Outages**

OC 4.11.1. The System Operator, in coordination with the Transmission Network Operators, shall prepare the Transmission Outage Program annually for the next three (3) years. The process shall culminate in development of the following three Programs scheduled over the time scales as indicated below:

(a) Committed Transmission Outage Program, covering real time up to end of Year 1;

(b) Provisional Transmission Outage Program, covering Year 2; and

(c) Indicative Transmission Outage Program, covering Year 3.

OC 4.11.2. The closer the outage program is to real-time operations, the more accurate it must be to ensure the Stability and Reliability of National Grid. As real-time approaches, there shall be regular exchange of information between each TNO and the System Operator, to update the Transmission Outage Program with the latest availabilities.

OC 4.11.3. The SO shall plan Transmission System Outages required in Years 2 and 3 as a result of construction or refurbishment works taking due account of the known requirements. The planning of Transmission System Outages required in Years 0 and 1 ahead will, in addition, take into account Transmission System Outages required as a result of maintenance.

OC 4.11.4. The SO shall coordinate the Transmission System Outages and Generating Unit Outages in such a way that the overall G&TOP has minimum impact on Users and total System cost. However, the SO shall have the discretion to determine the precedence of Generation or Transmission Outage over the other, on the basis of reasons relating to the proper operation of the National Grid.

OC 4.12. **Procedure**

OC 4.12.1. By the end of March Year 0, TNOs shall provide to the SO (in the forms notified by the SO from time to time), the following details of proposed Outages for inclusion in the Committed, Provisional, and Indicative Transmission Outage Programs, as defined in (OC 4.11.1) above:

(a) Identification of the Equipment and the MW capacity involved;

(b) Reasons for the maintenance;

(c) Expected duration of Outage (including time required for switching operations); and

(d) preferred start date and start time or range of start dates and start times;

OC 4.12.2. In rolling over the Transmission Outage Program from one year to the next, for every year, the procedure set out below is to be followed:

(a) submissions by the TNOs for Year 2 should reflect the current Indicative Transmission Outage Program; and

(b) submissions by the TNOs for Year 1 should reflect the current Provisional Transmission Outage Program.

(except, in any such case, to the extent that a TNO is reasonably responding to changed circumstances and changes which, in the context of the Outage Program, are minimal in their effect on the operation of the National Grid)

OC 4.12.3. By the end of September Year 0, the SO shall conduct Reliability analysis of the Transmission System for the operational planning horizon in light of the proposed Outages, for the various planning periods (Year 0, 1, 2, etc.) by considering the following factors:

(a) The forecasted Demand and its geographical distribution;

(b) Network Equipment loading and voltage profile;

(c) The requests by Users for changes in their Outage schedules;

(d) The maintenance requirements of the Transmission System;

(e) Generator/Interconnector Outages;

(f) The need to minimize the total impact of such Outage in respect of System Security and Reliability and/or Demand Management; and

(g) Any other relevant factor.

OC 4.12.4. For each proposed Outage, the SO shall determine the Users which will be operationally affected by the Outage and the approximate amount of Demand Management, if required. In case of possible Demand Management, the TNOs shall coordinate with the relevant Users and provide formal consent of the Users to the SO.

OC 4.12.5. The SO shall also indicate where a need exists to use inter-tripping, emergency switching, or other measures including restrictions on the Scheduling and Dispatch of Generating Units to allow the Security of the Transmission System to be maintained within allowable limits.

OC 4.12.6. During this period the SO may, as appropriate, contact any User which has supplied information to seek clarification on its information received or any other relevant information as is reasonable. The SO shall also notify to TNOs any concerns for their submitted Transmission Outage Programs and try to settle these through mutual discussion. If these cannot be resolved mutually, the TNOs must provide the SO with such evidence as the SO may reasonably require to substantiate that the proposed Outages cannot be modified. If the TNOs fail to establish to the reasonable satisfaction of the SO that the proposed Outage is inflexible, the SO can modify the Outage as per its requirements. All communication shall be recorded for future reference.

OC 4.12.7. The process of consultation and preparation of the Transmission Outage Program shall be concluded by Oct 31st of each year and published on the SO website.

OC 4.12.8. In proposing Outages, and in relation to all other matters under OC.4, the TNOs must act reasonably and in good faith. Without limitation to such obligation, each TNO shall act in accordance with Prudent Industry Practice in planning their Outages, so as to avoid a situation arising in which a TNO is obliged to schedule an Outage at short notice by reason of obligations imposed on it by statute, as a consequence of the TNO not having planned in accordance with Prudent Industry Practice, for example, by not having planned sufficiently in advance its Outages for any statutory time limit.

OC 4.13. **Changes to the Committed Transmission Outage Program within the Implementation Year (Year 0)**

OC 4.13.1. A request for a change to an Outage included in the Committed Transmission Outage Program may be initiated either by the SO or by a TNO at any time.

OC 4.13.2. Request initiated by the SO

(a) The SO may at any time request a TNO to change the timing or duration of any Outage in the Committed Transmission Outage Program where, in the SO’s reasonable opinion (were such Outage not to be deferred):

(i) the statutory or regulatory obligations could not be met; or

(ii) system Security, Reliability or Stability would be at risk.

(b) The SO may require the TNO to continue to defer such Outage for as long as the above situation persists. If a TNO responds by agreeing to the request, the Committed Transmission Outage Program shall be deemed to be amended accordingly.

(c) If a TNO declines the SO’s request, then the SO may negotiate with the TNO to reach a resolution. If a mutual resolution is not reached, then the TNO must provide the SO with such evidence as the SO may reasonably require to substantiate that Outage cannot be modified. If the TNO fails to establish to the reasonable satisfaction of the SO that the proposed modification is not possible, the Outage shall stand modified as per the SO requirements.

OC 4.13.3. **Outage Change Initiated by a TNO**

(a) A TNO may at any time request the SO for a change in the timing or duration of any Outage in the Committed Transmission Outage Program. Such requests should normally be initiated by giving not less than seven (7) days prior notice before the earliest start date of the Outage.

(b) Such a request must also include a valid reason for the proposed change in the Outage schedule.

(c) The SO shall evaluate whether the change is likely to have a detrimental effect on the secure operation of the Transmission System. This shall be done within a reasonable time frame, taking into consideration the extent of the change and the timing of the Outage.

(d) Where the request is not likely to have a detrimental effect on the secure operation of the Transmission System then the SO shall amend the Committed Transmission Outage Program accordingly. The TNO shall be advised by the SO that the change has been accepted.

(e) Where the Outage change is likely to have a detrimental effect on requirements for the secure operation of the Transmission System, then the SO shall not amend the Committed Transmission Outage Program. At the TNO's request, the SO may enter into discussions with the TNO to facilitate an alternative modification which may meet the requirements of the TNO, while not having an unacceptable effect on secure operation of the Transmission System. In the event that the TNO agrees with the proposed alternate, it shall submit a change request in accordance with OC 4.13.3 (a).

(f) Where the TNO has been notified that the change to the Committed Transmission Outage Program has not been accepted, the TNO shall not carry out any switching operations, otherwise it shall be considered a non-compliance.

OC 4.14. **Short Term Planned Maintenance (STPM) Outage**

OC 4.14.1. A TNO may request the SO at any time during Year 0, by giving not less than seven (7) days prior notice before the earliest start date, for a Short Term Planned Maintenance (STPM) Outage. The request notice must contain the following information:

(a) identity of the Equipment concerned;

(b) required duration of the Outage (which must not exceed six (6) hours); and

(c) preferred start date and start time or range of start dates and start times.

OC 4.14.2. On receipt of such a request, the SO shall consider the request and shall, after discussing the position with the TNO, reply indicating:

(a) acceptance of the request, confirming the requested start time and duration of the STPM Outage;

(b) proposals for the advancement or deferment of the requested STPM Outage, indicating alternative start time and duration; or

(c) rejection of the request.

OC 4.14.3. If the SO accepts the request, the STPM Outage, if taken, must be taken by the TNO in accordance with the request. If the SO has indicated an alternative start time and/or duration, the SO and the TNO may discuss the alternative and any other options which may arise during the discussion. If agreement is reached, then the Outage, if taken, must be taken by the TNO in accordance with the agreement. If the request is refused by the SO or if agreement is not reached, then the TNO will not take the Outage.

OC 4.14.4. For the proposed STPM outage, the SO shall determine the Users which will be operationally affected by the Outage and the approximate amount of Demand Management, if required. In case of possible Demand Management, the TNO shall coordinate with the relevant Users and provide formal consent of the Users to the SO.

OC 4.14.5. Not Used

OC 4.14.6. In the event that an STPM Outage is scheduled pursuant to OC 4.14, the SO shall confirm the details of the approval of the STPM Outage. Such notice shall contain the following information:

(a) the identity of the Equipment concerned;

(b) Not Used

(c) duration of the Outage; and

(d) the start date and start time of the Outage.

OC 4.15. **De-energization of Transmission Equipment**

OC 4.15.1. A TNO may only undertake Planned Outages with the SO agreement in accordance with the Outage Program produced pursuant to the provisions of this OC 4.

OC 4.15.2. In real time operation, no Equipment shall be de energized for an Outage without express formal permission of the SO according to the procedures set out in OC 4.13 and OC 4.14.

OC 4.15.3. The SO’s express formal permission shall specify:

(a) the identity of the Equipment on Outage

(b) the duration of the Outage; and

(c) the start date and start time of the Outage.

OC 4.15.4. The SO may withhold its permission for the Planned Outage where such Outage has previously been planned in accordance with OC 4.13.2.

OC 4.16. **Notified Unplanned Outage**

OC 4.16.1. If a TNO requires an Unplanned Outage which cannot reasonably be requested to the SO as per OC 4.14, it must provide notice to the SO as early as possible. Such notice must include an identification of the Equipment, the expected start date and start time and duration of the Unplanned Outage and the nature of the Outage together. The SO will acknowledge such notice as soon as reasonably possible after the notice is received by the SO.

OC 4.16.2. The SO may request the TNO to advance or defer the Outage. If the TNO agrees to such a request, the TNO shall send the SO a notice confirming this agreement. The SO will acknowledge this notice. The TNO must then take the Outage in accordance with this agreement.

OC 4.16.3. A TNO shall use all reasonable endeavors to ensure that, following an Unplanned Outage, the Equipment is repaired and restored as soon as possible and in accordance with Prudent Industry Practice.

OC 4.16.4. However, the SO reserves the right to Investigate whether the Outage was unavoidable or could not have been planned in time.

OC 4.17. **Return to Service and Overruns**

OC 4.17.1. If at any time during an Outage, the TNO becomes aware that the Equipment will not have been maintained, repaired or restored to be available by the expiry of the period specified for the duration of the Outage in the Committed Transmission Outage Program or as otherwise notified in the case of Outages other than Planned Outages, the TNO shall notify the SO immediately, stating the reason(s) for the delay and a best estimate of the date and time by which the Equipment will actually have been maintained, repaired, or restored to be available.

OC 4.17.2. A TNO must use all reasonable endeavors to ensure that, in respect of each Planned Outage, the Outage schedule as included in the Committed Transmission Outage Program (or as moved in accordance with the provisions of this section) is followed.

OC 4.18. **Annual Production Plan (APP)**

OC 4.18.1. Based on the Committed G&TOP, the System Operator shall prepare an indicative Annual Production Plan indicating:

(a) estimated monthly capacity and energy requirements to support the forecasted peak Demand along with adequate Operating Reserve.

(b) estimated peak and average production from each Generator.

(c) any periods of inadequate Operating Reserve and Demand Management required.

OC 4.18.2. For the avoidance of doubt, the APP prepared and published by SO is indicative and is only intended to provide an outlook of the National Grid operations. Nothing contained in the APP shall relieve any of the Users from their obligations established under the Grid Code or any other relevant document.

COMMITTED GENERATION OUTAGE PROGRAM TIMETABLE

This appendix should be completed by the System Operator in consultation with the Generators and other relevant stakeholders.

PROVISIONAL GENERATION OUTAGE PROGRAM TIMETABLE

This appendix should be completed by the System Operator in consultation with the Generators and other relevant stakeholders.

INDICATIVE GENERATION OUTAGE PROGRAMTIMETABLE

This appendix should be completed by System Operator in consultation with the Generators and other relevant stakeholders.

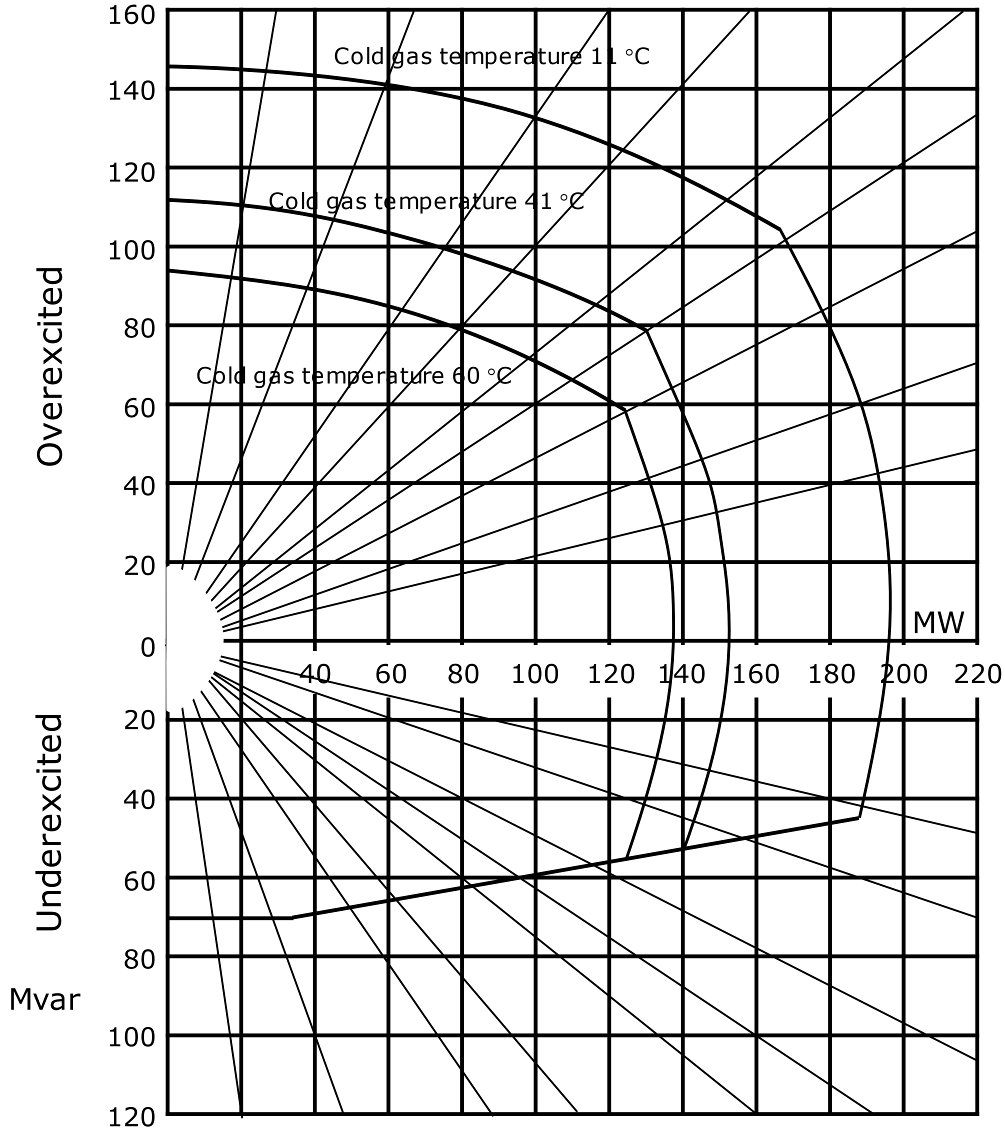
TRANSMISSION OUTAGES

Primary or bulk and secondary transmission outages

This appendix should be completed by System Operator in consultation with the generators and other relevant stakeholders.

Generator Performance Chart, Example

Rated Apparent Power	S_NMVA	Rated Frequency	f_N = 50 Hz
Rated Active Power	P_N MW	Power Factor	P.F. = 0.95
Rated Armature Voltage	V_N kV	Speed	n_N =50 s^{01}
Rated Armature Current	I_N kA	Cold Air Temperature	T_K = 41 °C



GENERATION PLANNING PARAMETERS

The following parameters are required in respect of each Genset.

Regime Unavailability

Where applicable the following information must be recorded for each Genset.

a) Earliest synchronizing time; and

b)Latest de-synchronizing time.

Synchronizing Intervals

The Synchronizing intervals between Gensets.

De-Synchronizing Interval

A fixed value de-synchronizing interval between Gensets.

Synchronizing Generation

The amount of MW produced at the moment of Synchronizing.

Minimum on Time

The minimum period on-load between synchronizing and De-synchronizing.

Run-Up Rates

A run-up characteristic consisting of different stages from Synchronizing Generation to Output Usable.

Run-Down Rates

A run down characteristic consisting of different stages from Output to Desynchronizing.

Notice to Synchronize (NTS)

The period of time required to Synchronize a Genset.

Minimum Shutdown Time

The minimum interval between De-synchronizing and Synchronizing a Genset.

Maximum Shifting Limit

The maximum number of times that a Genset may De-synchronize per

Operational Day.

Gas Turbine Units Loading Parameters

a) Loading rate for fast starting

b)Loading rate for slow starting

TECHNICAL PARAMETERS - VRES/BESS

This appendix should be completed by the System Operator in consultation with the VREs and BESS Plants and other relevant stakeholders.

TECHNICAL PARAMETERS - INTERCONNECTORS

This appendix should be completed by the System Operator in consultation with the Interconnectors and other relevant stakeholders.

OC 5. **SYSTEM SERVICES**

OC 5.1. **Introduction**

OC 5.1.1. This OC deals with System Services which are essential to the proper functioning of the National Grid including:

(a) Frequency Control;

(b) Operating Reserve;

(c) Voltage/Reactive Power Control; and

(d) Black Start;

OC 5.1.2. In order to ensure secure operation, the SO shall have control over all System Services; i.e. the SO shall specify what System Services are to be provided when, where and by whom.

OC 5.1.3. System Services mentioned in OC 5.1.1 (a) to (d) above are Ancillary Services and shall be compensated, if applicable, as per provisions of the Commercial Code.

OC 5.1.4. Nothing contained in this OC 5 shall restrict a User from providing System Services that are better than the requirements established in this OC.

OC 5.2. **Objectives**

OC 5.2.1. The objectives of this OC are:

(a) to establish a policy to ensure Frequency Control capability in the National Grid for operational control by the SO, and to set out appropriate procedures to enable the SO to control the National Grid frequency and (insofar as practicable) maintain it within the limits specified in this OC;

(b) to set out the types and amounts of Reserve, as provided in a number of time scales, which make up the Operating Reserve that the SO may make use of under certain operating conditions for Frequency Control.

(c) to set out the control strategies to be used by the SO, in conjunction with Users where appropriate, for controlling the Transmission System voltages and Reactive Power;

(d) to describe the various time scales for which Operating Reserves are required, the policy which will govern the Dispatch of the Operating Reserves, and the procedures for monitoring the performance of Generating Units and other Operating Reserve providers; and

(e) to set out requirements relating to Black Start Stations to enable the SO to manage the recovery of the National Grid back to normal from a Partial or Total Shutdown.

OC 5.3. **Scope**

OC.5 applies to the SO and to the following, each of which is a User under this OC5:

(a) Generators;

(b) Energy Storage Units;

(c) DISCOs;

(d) Transmission Network Operators;

(e) Bulk Power Consumers;

(f) Interconnectors.

OC 5.4. **Frequency Control**

OC 5.4.1. To maintain the security and integrity of the National Grid, it is necessary that the SO operates the Transmission System and Dispatches supply and demand resources in such a manner as to provide adequate Frequency Control in the Transmission System to achieve its operation within the applicable Frequency limits at all times.

OC 5.4.2. In order to cater for normal frequency fluctuations, Demand/VRE forecast variations and to cover against a sudden loss of generation or a major in-feed from the Transmission System, it is necessary that sufficient Operating Reserve is maintained through the Control Phase.

OC 5.4.3. Operating Reserve is the additional output from Generating Units or Demand Control which is realizable in real time to aid in containing and correcting System frequency from falling beyond an acceptable level due to loss of Generation or a mismatch between Supply and Demand.

OC 5.4.4. **Operating Frequency Limits**

The System Operator shall co-ordinate with all the Users connected to Transmission System in order to maintain the declared system frequency at 50 Hz (Cycles/sec) with the following allowance excursions:

(a) Declared or Target System Frequency shall be 50Hz ± 0.05Hz.

(b) Frequency Sensitive Mode shall be 49.8 Hz-50.2 Hz. Such a variation is permissible to allow frequency variations while ramping up generation and load pick-up.

(c) Protected periods of operation of the system at the frequency in the range of 49.5 Hz- 50.5 Hz (Tolerance Frequency Band).

(d) Minimum/Maximum Acceptable Frequency Band shall be 49.4 Hz-50.5 Hz (Load Shedding Threshold or Contingency Frequency Band), which means the maximum expected absolute value of an instantaneous frequency deviation after the occurrence of an imbalance, beyond which SO shall deploy emergency measures such as Demand Control or Automatic Low Frequency Demand Disconnection.

(e) A Significant Frequency Disturbance Event is deemed to have occurred if the Frequency falls below 49.40 Hz.

(f) Instantaneous frequency excursions are to be handled in the following manner:

(i) In the event of a single contingency, the power system frequency must be maintained within "Tolerance Frequency Band" within 5 minutes of the excursion, and to within the "Frequency Sensitive Mode" within 10 minutes of the contingency.

(ii) Instantaneous frequency excursions outside the "Contingency Frequency Band" shall be handled in such a manner that:

(iii) System frequency returns to "Contingency Frequency Band" within 60 seconds.

(iv) System frequency returns to "Tolerance Frequency Band" within 5 minutes, and within the "Frequency Sensitive Mode" within 30 minutes.

(g) For avoidance of doubt, the operating ranges mentioned above are the limits for System Frequency which are to be maintained by the SO (insofar as practicable) to comply with NERPA Performance Standards to ensure Power Quality in Normal State. The Frequency limits provided in CC 5.6 are withstand capabilities for User Equipment within which the User shall remain Connected with the Transmission System.

Table OC.5-1: OPERATING FREQUENCY LIMITS

Sr. No.	Description	Frequency Limits
1	Target Frequency	50 ± 0.05 Hz
2	Frequency Sensitive Mode	49.8 Hz to 50.2 Hz
3	Tolerance Frequency Band	49.5 Hz to 50.5 Hz
4	Contingency Frequency Band	49.4 Hz to 50.5 Hz

OC 5.4.5. **Description of Frequency Control**

OC 5.4.5.1. Frequency Control occurs in three stages, namely:

(a) Primary Frequency Control;

(b) Secondary Frequency Control; and

(c) Tertiary Frequency Control.

OC 5.4.6. **Primary Frequency Control**

OC 5.4.6.1. Primary Frequency Control takes place in a time scale immediately following a change in Frequency and reaches its maximum value within 10 seconds which is sustainable up to 30 seconds, and is achieved by automatic corrective responses to Frequency deviations occurring on the Transmission System. This automatic correction arises from:

(a) System inertia of rotating synchronous generators

(b) Natural frequency demand relief of motor load;

(c) Automatic MW output adjustment of Synchronous Generating Units initiated by Free Governor Response or other responses including peaking of Combustion Turbine Units, condensate stop;

(d) Automatic MW output adjustment of Non-Synchronous Generating Units technically possible.

OC 5.4.7. **Primary Frequency Control of Synchronous Generators**

OC 5.4.7.1. Primary Frequency Control maintains the balance between the Load and Generation using turbine speed governors. It is an automatic decentralized function of the turbine governor to adjust the generator output of a unit as a consequence of a Frequency deviation. The need for the Governor Control mode lies in the fact that the Generating Units should be able to correct their own Frequency when a disturbance occurs in the system, considering the difference of the speed of the Generating Units depending on the type of technology. Thus, Generating Plants shall not depend on the System by drawing power (MW) to correct their Frequency.

OC 5.4.7.2. All Generating Units when Synchronized to the Transmission System shall be able to provide:

(a) Free Governor Control Action (FGC) through a Governor Control System, to maintain system frequency within the prescribed limits provided in this OC;

(b) The Active Power Frequency Response shall be capable of having a Governor Droop between 2% and 12%. The default Governor Droop setting shall be 4%.

(c) No time delays other than those necessarily inherent in the design of the Governor Control System shall be introduced.

(d) A Frequency Dead band of no greater than +/- 0.05 Hz may be applied to the operation of the Governor Control System. The design, implementation and operation of the Frequency Dead band shall be agreed with the SO prior to commissioning of the Generating Unit/Station.

OC 5.4.7.3. The amount of Frequency Response in MW that the synchronized Generators can provide cumulatively under Free Governor Control is known as "Primary Operating Reserve". For Low Frequency Events, each Generator shall be capable of providing:

(a) minimum Primary Operating Reserve of 5% Registered Capacity while operating at MW Output of 95% of Registered Capacity

(b) While operating at MW Output in the range from 50% to 95% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output to 5% at 95% MW output

(c) While operating at MW Output in the range of 95% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 5% of Registered Capacity at 95% output to 0 at 100% output.

(d) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

OC 5.4.7.4. The Generator may only restrict governor action where:

(a) the action is essential for the safety of personnel and/or to avoid damage to Plant, in which case the Generator shall inform the SO of the restriction without delay; or

(b) in order to (acting in accordance with Good Industry Practice) secure the reliability of the Generating Unit; or

(c) the restriction is agreed between the SO and the Generator in advance; or

(d) the restriction is in accordance with a Dispatch Instruction given by the SO.

(e) Users shall justify their actions by reporting to the SO about their event.

OC 5.4.7.5. In the event that the SO either agrees to a restriction on governor action or instructs such a restriction, the SO shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction.

OC 5.4.8. **Primary Frequency Control of Non-Synchronous Generators**

OC 5.4.8.1. Non-Synchronous Generators will typically provide Primary Frequency Response through Energy Storage Units (such as BESS) and are also required to comply with the provisions of this section at all times unless permitted in exceptional circumstances as laid down in OC 5.4.8.6 below.

OC 5.4.8.2. Non-Synchronous Generators when connected to the Transmission System shall operate at all times under the control of a Frequency Regulation system, unless otherwise specified by the SO, with characteristics within the appropriate ranges as per their Technical Parameters;

OC 5.4.8.3. No time delays other than those necessarily inherent in the design of the Frequency Control shall be introduced;

OC 5.4.8.4. Frequency sensitivity shall be activated for any frequency deviations exceeding ± 0.05 Hz, except for those Non-Synchronous Generators for which Frequency Regulation service is not activated on instructions of the SO.

OC 5.4.8.5. Not Used

OC 5.4.8.6. Non-Synchronous Generators may only restrict the Frequency Control Action in some exceptional circumstances, to be agreed with the SO in advance, when doing so becomes essential for any of the following situations:

(a) for the Safety of personnel and/or to avoid damage to Plant;

(b) to secure the Reliability of the Non-Synchronous Generators;

(c) the restriction is agreed upon between the SO and the Non-Synchronous Generators in advance;

(d) The restriction is in accordance with a Dispatch Instruction issued by the SO.

(e) Users shall justify their actions by reporting to the SO about their event.

OC 5.4.8.7. Such actions shall be brought to the notice of the SO immediately, and the SO shall record them properly.

OC 5.4.8.8. Wind and Solar PV/CSP Power Plants shall be exempted from the responsibility of Frequency Regulation and Control for the "Frequency Sensitive Mode" unless they are equipped with such a control system (such as BESS). However, for Tolerance Frequency Band, OC 5.4.13.14 shall be applicable.

OC 5.4.9. **Primary Frequency Control of Interconnectors**

OC 5.4.9.1. Interconnectors when Energized shall operate at all times in Frequency Control mode, unless otherwise specified by the SO, with characteristics within the appropriate ranges as specified in Connection Code;

OC 5.4.9.2. The Interconnector Frequency Droop shall normally be 4% and shall be settable between 2% and 12%;

OC 5.4.9.3. No intentional time delays other than those agreed with the SO shall be introduced into the frequency response system;

OC 5.4.9.4. The Frequency Dead band shall normally be zero. Any non-zero dead band must be agreed in advance with the SO and shall not exceed +/- 0.05Hz.

OC 5.4.9.5. Interconnectors shall not act to control the frequency in an Other System unless agreed in advance with the SO and the Interconnector.

OC 5.4.9.6. For Low Frequency Events, each Interconnector shall be capable of providing:

(a) minimum Primary Operating Reserve of 5% Registered Capacity while operating at MW Output of 95% of Registered Capacity

(b) While operating at MW Output in the range from 50% to 95% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output to 5% at 95% MW output

(c) While operating at MW Output in the range of 95% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 5% of Registered Capacity at 95% output to 0 at 100% output.

(d) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

OC 5.4.9.7. The Interconnector may only restrict the action of the Frequency Control mode in such as a manner as to contravene the terms of OC 5.4.9.1 where:

(a) The action is essential for the safety of personnel and/or to avoid damage to Plant, in which case the Interconnector shall inform the SO of the restriction without undue delay; or

(b) in order to (acting in accordance with Good Industry Practice) secure the reliability of the Interconnector, in which case the Interconnector shall inform the Reference SO of the restriction without undue delay; or

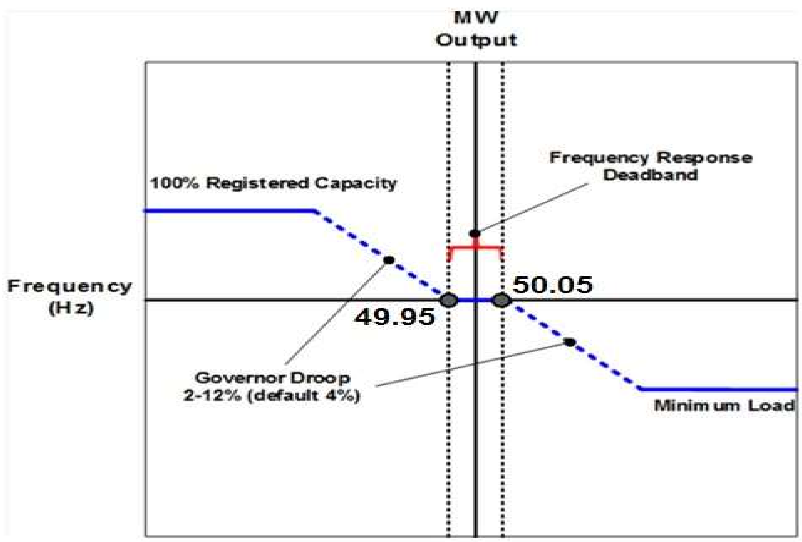
(c) the restriction is agreed between the Reference SO and the Interconnector in advance; or

(d) the restriction is in accordance with a Dispatch Instruction given by the Reference SO.

(e) Users shall justify their actions by reporting to the SO about their event.

OC 5.4.9.8. In the event that the SO in accordance with OC 5.4.9.7 either agrees to a restriction on the control action or instructs such a restriction, the SO shall record the nature of the restriction, the reasons, and the time of occurrence and duration of the restriction.

Figure OC.5-1. Primary Frequency Control



OC 5.4.10. **Secondary Frequency Control**

OC 5.4.10.1. Frequency deviations, outside the levels specified in OC 5.4.4 (b) such as those that may occur on the loss of Generating Unit(s), Interconnectors, Demand Consumers or other MW input into the Transmission System or the Distribution System are corrected through the use of Secondary Frequency Control.

OC 5.4.10.2. Secondary Frequency Control takes place in the time scale from 5 seconds following the change in Frequency and achieves its maximum value within 30 seconds which is sustainable up to 30 minutes.

OC 5.4.10.3. Secondary Frequency Control acts directly on the MW Outputs of participating Generating Units, on the Active Power transfer to or from Interconnectors and on the MW input of Demand Side Units. This automatic action facilitates more frequent MW output adjustments than is practicable by means of Dispatch Instructions and manual set point adjustment, thus allowing more frequent and rapid Frequency correction.

OC 5.4.10.4. The Secondary Frequency Control operational on the Transmission System is normally carried out through "Automatic Generator Control" (AGC).[2]

OC 5.4.10.5. Generating Units and Interconnectors with a Registered Capacity in accordance with CC 6.3.1 (l) shall provide Secondary Frequency Control as instructed by SO.

OC 5.4.10.6. SO shall determine which Generators/Interconnectors shall participate in AGC for Secondary Frequency Control, based on their Technical Parameters and real time conditions. Other than as provided for in OC 5.4.10.11 and OC 5.4.10.12, all Generating Units and Interconnectors participating in AGC shall operate under the control of AGC when within their AGC Control Range.

OC 5.4.10.7. SO shall maintain appropriate reserve (headroom) in the participating Generators to allow them to vary their MW Output under Automatic Generation Control.

OC 5.4.10.8. The amount of Frequency Response in terms of MW available from all Generators participating in Secondary Frequency Control is known as “Secondary Operating Reserve”.

OC 5.4.10.9. For Low Frequency Events, each Generator/Interconnector shall be capable of providing:

(a) minimum Primary Operating Reserve of 10% Registered Capacity while operating at MW Output of 90% of Registered Capacity

(b) While operating at MW Output in the range from 50% to 90% Registered Capacity, the amount of Frequency Response shall not be less than that indicated by a straight line with unity rise from 50% of Registered Capacity at 50% MW output, to 10% at 90% MW output

(c) While operating at MW Output in the range of 90% to 100% Registered Capacity the amount of Frequency Response shall not be less than that indicated by a straight line with unity decay from 10% of Registered Capacity at 90% output to 0 at 100% output.

(d) For High Frequency Events, the minimum amount of Frequency Response shall be vice versa with 50% of Registered Capacity at 100% MW Output and 0 at 50% MW Output.

OC 5.4.10.10. Secondary Frequency Control shall not impair the action of the Primary Frequency Control. These actions of Secondary Frequency Control will take place simultaneously and continually, both in response to small deviations (which will inevitably occur in the course of normal operation) and in response to a major discrepancy between generation and Demand (associated e.g. with the tripping of a generating unit or network).

OC 5.4.10.11. In the event that the Generator or Interconnector (acting in accordance with Good Industry Practice) considers that it is necessary to secure the reliability of a Generating Unit or Interconnector, or for the safety of personnel and/or Plant, to prevent a Generating Unit or Interconnector from operating under AGC, and

[2] In case AGC is not available in the System due to any reason, the Secondary Operating Reserves shall be operated manually for frequency regulation. In such case, the response time mentioned in OC 5.4.10.2 is impracticable, and the SO shall use its best efforts to manually operate the Reserve as fast as practicable. However, it is clarified that during this emergency, System Reliability and Power Quality would be at risk and all possible endeavours must be made by all Users to restore AGC in the System.

commences to control the MW output manually, then the Generator or Interconnector shall inform the SO of this without delay. Generators and Interconnector shall also inform the SO of the reasons for not operating the Generating Unit or Interconnector under AGC, and the course of action being taken to rectify the problem forthwith. When the problem has been rectified, the Generator or Interconnector shall contact the SO to arrange for the Generating Unit or Interconnector to return to operation under the control of AGC. Users shall justify their actions by reporting to the SO about their event.

OC 5.4.10.12. The SO may issue a Dispatch Instruction to a Generator or Interconnector to prevent a Generating Unit or Interconnector (equipped with AGC) from operating under AGC, in accordance with SDC2.

OC 5.4.10.13. Generating Units or Interconnectors not operating under AGC for reasons set out in OC 5.4.11.11 and OC 5.4.11.12 shall nevertheless continue to follow MW Dispatch Instructions as required by SO.

OC 5.4.11. **Tertiary Frequency Control**

The goal of Tertiary Frequency Control is to restore the reserves that were used during Primary and Secondary Frequency Control. Reserves may be restored using re-dispatch, commitment of resources, or establishing new Interconnector schedules. Restoring these reserves completes the repositioning of the National Grid so that it is prepared to respond to a future loss-of-generation event. Tertiary Frequency Control is utilized using following reserves:

OC 5.4.11.1. **Replacement Reserve**

Replacement Reserve is the additional MW output (and/or reduction in Demand) required compared to the pre-incident output (or Demand) which is fully available and sustainable over the period from 20 minutes to 4 hours following an Event. Each Generator/Interconnector shall be capable of providing Replacement Reserve not less than 10% Registered Capacity, at a minimum, at MW Outputs in the range from 50% to 90% Registered Capacity, with provision in the range of 90% to 100% Registered Capacity to be not less than that indicated by a straight line with unity decay from 10% of Registered Capacity at 90% output to 0 at 100% output

OC 5.4.11.2. **Contingency Reserve**

Contingency Reserve is the margin of available Generation Capacity over Forecast Demand, which is required in the period from twenty-four (24) hours ahead down to real time, to cover against uncertainties in the availability of Generation Capacity and also against weather forecast and Demand Forecast uncertainties. Contingency Reserve is provided by Generating Plants which are not required to be Synchronized, but which must be available to Synchronize with the System within a time scale as specified by the SO while preparing Indicative Dispatch Schedule (IOS) as per SDC 1.

OC 5.4.12. **Operating Reserve Policy**

OC 5.4.12.1. The SO shall determine any reserve requirements, including the amount of Primary Operating Reserve, Secondary Operating Reserve, Tertiary Operating Reserve to be kept to ensure system security, which shall typically be equal to the largest Generating Unit. However, due consideration will also be taken of relevant factors, including but not limited to the following:

(a) the relevant SO operating policy in existence at that time;

(b) the magnitude and number of the largest generation infeed to the Transmission System at that time, including infeed over Interconnectors and also over single transmission feeders within the Transmission System and also the amount of Generation that could be lost following a single Contingency;

(c) the extent to which Demand Management allowed under the relevant standard have already occurred within the then relevant period;

(d) the elapsed time since the last Demand Management incident;

(e) particular events of national or widespread significance, which may justify provision of additional Operating Reserve;

(f) the cost of providing Operating Reserve at any point in time;

(g) Expected demand/VRE generation forecast variations;

(h) ambient weather conditions, insofar as they may affect (directly or indirectly) Generating Unit and/or Transmission System reliability;

(i) the predicted Frequency drop on loss of the largest infeed as may be determined through simulation using a dynamic model of the National Grid;

(j) constraints imposed by agreements in place with Externally Interconnected Parties;

(k) uncertainty in future Generation output.

OC 5.4.12.2. SO shall keep records of significant alterations to the Operating Reserve policy so determined under OC 5.4.12.

OC 5.4.12.3. **Contingency Reserve**

The SO shall determine the amount of Contingency Reserve required for each time scale up to 24 hours ahead, taking due consideration of relevant factors, including but not limited to the following:

(a) historical Availability Factor and reliability performance of individual Generating Units;

(b) notified risk to the reliability of individual Generating Units; and

(c) Demand/VRE forecasting uncertainties;

(d) Status and availability of Demand Side Units and

(e) status and availability of Interconnectors.

Table OC.5-2: Primary, Secondary & Tertiary Frequency Control Summary

Name	Timescale	Description	Type of Operating Reserve	Participants	Quantum
Primary Frequency Control	0-10 sec and sustainable up to 30 sec	Free Governor Control/Non Synchronous Frequency Control	Primary Frequency Reserve	Fitted on all Generators and ESUs, including Embedded Generators and always activated.	As per Generators on-bar
Secondary Frequency Control	5 sec-30 sec and sustainable up to 30 min	Automatic Generation Control (AGC)	Secondary Frequency Reserve	Fitted on all Generators and activated on SO instructions	Largest Generating Unit
Tertiary Frequency Control	20 min-4 hrs	Re-dispatch/ Synchronization	Replacement Reserve	Re-dispatch/Synchronization of Generators to restore Primary and Secondary Reserves	Largest Generating Unit
	24 hr ahead to real time		Contingency Reserve		

OC 5.4.13. **Responsibilities of the SO in Respect of Operating Reserve**

OC 5.4.13.1. The SO shall, in accordance with Prudent Utility Practice, make reasonable endeavors to Dispatch generation and operate the system in compliance with the SO's determinations as per Operating Reserve policies made from time to time.

OC 5.4.13.2. The SO's sole responsibility, having met its obligations under the preceding provisions of OC.5.4, shall be to, acting in accordance with Prudent Utility Practice, Dispatch such Generating Units as are available required to meet:

(a) System Demand; and

(b) the level of Operating Reserve required by the SO's prevailing Operating Reserve policies.

OC 5.4.13.3. The SO shall Monitor the Frequency Response provided by Users for compliance. In evaluating the adequacy of the performance of a Generator/Interconnector, the SO shall compare the actual performance as measured, with the expected performance for that Generating Unit or Interconnector. The expected performance from the Generating Unit or Interconnector shall be calculated based on the Frequency deviation from the pre-incident Frequency, and the values of Response expected from the Generating Unit or Interconnector.

OC 5.4.13.4. In the event of a Generating Unit not providing Frequency Response, unless instructed by SO, the SO may impose restrictions on the operation of the

Generating Unit in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-Energize, or not energize/synchronize the Generating Unit.

OC 5.4.13.5. In the event of an Interconnector not providing Frequency Response, the SO may impose restrictions on the operation of the Interconnector in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Interconnector to De-Energize, or not connect/synchronize with the Interconnector.

OC 5.4.13.6. Following the occurrence of a Significant Frequency Disturbance, the SO shall analyze the adequacy of the provision of Operating Reserve and may re-evaluate the amount of Reserve to be maintained in the System.

OC 5.4.13.7. If the System Operator foresees that there will be insufficient Operating Reserve, it shall discuss this problem with the Users, and seek to change the plant mix to ensure that there shall be sufficient Operating Reserve in the System.

OC 5.4.13.8. **Action required by Generators/ESU in response to Low Frequency Events:**

(a) If System Frequency falls to below 49.95Hz, each Generator will be required to check that each of its CDGUs is achieving the required level of response including that required from the Governor Control System, where applicable, in order to contribute to containing and correcting the low System Frequency.

(b) Generators/ESUs shall be capable of providing a power increase up to Registered Capacity.

(c) ESUs shall be capable of disconnecting their load. This requirement does not extend to auxiliary supplies.

(d) Where the required level of response is not being achieved, appropriate action should be taken by the Generators/ESUs without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Generator's/ESU's local security and safety conditions permit.

OC 5.4.13.9. **Action required by Generators/ESUs in response to High Frequency Events:**

If System Frequency rises to or above 50.05 Hz, each Generator will be required to ensure that its CDGUs have responded in order to contribute to containing and correcting the high System Frequency by automatically:

(a) reducing MW Output without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Generator's local security and safety conditions permit.

(b) Generators shall be capable of providing a power decrease down to Minimum Load. ESUs shall be capable of decreasing supply/increasing load as per Technical Parameters.

(c) Stable operation shall be ensured.

(d) Generating Units shall be capable of continuous stable operation when MW Output is reduced to Minimum Load. This response will prevail over any other Active Power control mode.

(e) Where the required level of response is not being achieved, appropriate action should be taken by the Generators without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Generator's local security and safety conditions permit.

OC 5.4.13.10. **Action required by Interconnectors in response to low Frequency:**

(a) If System Frequency falls to below 49.95 Hz, each Interconnector will be required to ensure that it has responded in order to contribute to containing and correcting the low System Frequency by automatic increasing the Active Power input to the Transmission System or decreasing the Active Power import from the Transmission System without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Interconnector's local security and safety conditions permit.

(b) Any such action shall be in accordance with the relevant Agreement(s) between the Interconnector and the SO.

OC 5.4.13.11. **Action required by Interconnectors in response to high Frequency:**

(a) If System Frequency rises above 50.05 Hz, each Interconnector will be required to ensure that it has responded in order to contribute to containing and correction of the high System Frequency by automatic decreasing the Active Power input to the Transmission System or increasing the Active Power import from the Transmission System without delay and without receipt of instruction from the SO to achieve the required levels of response, provided the Interconnector's local security and safety conditions permit.

(b) Any such action shall be in accordance with the relevant Agreement(s) between the Interconnector and the SO.

OC 5.4.13.12. **Action required by Interconnector in response to External System Frequency Events**

Automatic MW set-point changes of Interconnectors triggered by Frequency Events on the External System shall be agreed between the Interconnector and the SO, in accordance with the relevant Agreement(s).

OC 5.4.13.13. **Action required by embedded HVDC**

For the purpose of Frequency Control:

(a) Embedded HVDC systems shall be equipped with an independent control mode to modulate the Active Power output of the HVDC converter station depending on the frequencies at all Connection Points of the HVDC system in order to maintain stable system frequencies.

(b) The SO shall specify the operating principle, the associated performance parameters and the activation criteria of the frequency control referred to point (a) above, as per relevant Agreement(s).

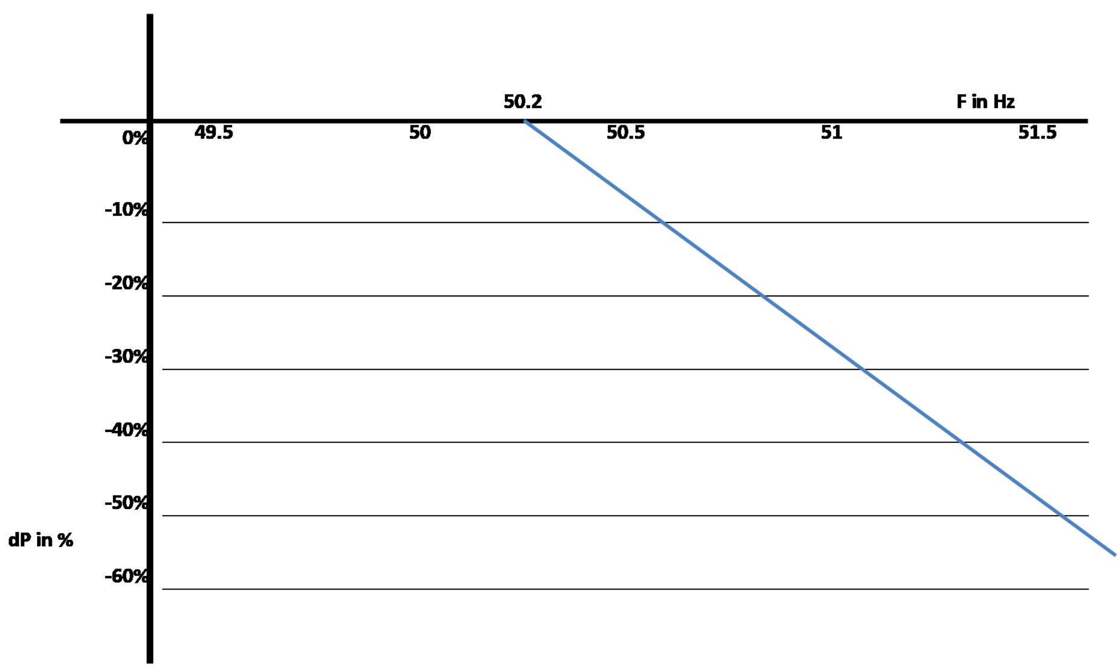
OC 5.4.13.14. **Action required by Wind and Solar PV/CSP Power Plants in response to low Frequency:**

When frequency enters "Tolerance Frequency Band", with lower range defined as 49.5 Hz, all Wind and Solar PV/CSP Power Plants shall have the technical capability to contribute in frequency stabilization by maintaining appropriate active power reserve in proportion to available power of Plant dependent on availability of wind/ solar radiation at the instant when such variations would occur.

OC 5.4.13.15. **Action required by Wind and Solar PV/CSP Power Plants in response to high Frequency:**

Above 50.2Hz, when frequency enters "Tolerance Frequency Band", with upper range defined as 50.5 Hz, all Wind and Solar PV/CSP Power Plants shall contribute to frequency stabilization by reducing active power (as per SO instructions) as described in Figure below:

Figure OC.5-2: Active Power and Frequency Control of VRE Plants



OC 5.5. **Voltage/Reactive Power Control**

OC 5.5.1. In order to maintain security and integrity of the Transmission System, to avoid damage to the Transmission System and to User facilities, and to maintain Voltages in the Transmission System within the limits specified in the OCC 5.5.7, it is necessary for the SO to control Transmission System Voltages.

OC 5.5.2. Voltage control of power systems requires that a MVAR demand is met and that sufficient dynamic Voltage control capability is available on the

Transmission System to cover changes in the MVAR demand such as result from Demand variations, to facilitate controlled Voltage adjustment and to limit the duration and extent of Voltage fluctuations under fault conditions. The SO shall endeavor to maintain sufficient availability of dynamic and static reactive power in order to maintain Transmission System Voltages at Connection Points within the limits specified in OC 5.5.7, at all times.

OC 5.5.3. OC5.5 sets out the procedures for the utilization of User Plant or facilities by the SO for the purposes of Transmission System Voltage control, where appropriate. Some procedures for implementation of Voltage control strategies (e.g. Generating Unit MVAR Dispatch, Interconnector MVAR Dispatch etc.) are addressed under the provisions of SDC 2, and therefore this OC 5.5 shall be read in conjunction with those provisions.

OC 5.5.4. Factors that influence the required MVAR capacity include:

(a) charging capacitance of the Transmission System.

(b) User MVAR Demand.

(c) Transmission System MVAR losses.

(d) Generating Unit MVAR production or absorption.

(e) Interconnector MVAR production or absorption.

(f) Voltage Control facilities, such as capacitor banks and reactors.

OC 5.5.5. The effects of Transmission System capacitance can be controlled by controlled variation of the Transmission System Voltage. Thus at times of high MVAR Demand (normally times of high MW Demand), the Transmission System Voltage may be operated towards the upper portion of the allowable control range, and at times of low MVAR Demand (normally times of low MW Demand), the Transmission System Voltage may be operated towards the lower portion of the allowable control range. This daily variation is typically required for operation of the Transmission System.

OC 5.5.6. Due to the electrical characteristics of the Transmission System, the Voltage (for Plant operated at the same nominal Voltage) will not be the same at all points on the Transmission System and may vary within the operating voltage limits give in OC 5.5.7.

OC 5.5.7. **Operating Voltage Limits**

The SO shall maintain the operating Voltage of the System within Target Voltage Levels specified in Table OC 5-3. The system operating Voltage shall be maintained within these limits both for Normal Operating Conditions and Contingency Conditions excluding transient and abnormal System conditions.

(a) Under (N-0) Normal Operating Conditions: The bus voltages shall be within the bandwidth of +4.58/-4.84% of the Nominal System Voltage for 765 kV voltage level and +8% and -5% of Nominal System Voltage for 500 kV, 220 kV, 132 kV and 66 kV voltage level.

(b) Under (N-1) Contingency Operating Conditions: The bus voltages shall be within the bandwidth of +4.58/-6.8% of the Nominal System Voltage for 765 kV Voltage level while ±10% of the Nominal System Voltage for 500 kV, 220 kV, 132 kV and 66 kV voltage level.

Table OC.5-3: System Operating Voltage Limits

Voltage Level (kV)	Normal Condition		N-1 Condition	
	Max kV	**Min kV**	**Max kV**	**Min kV**
765	800	728	800	713
500	540	475	550	450
220	238	209	245	198
132	142	125	145	119
66	70	63	72	59

These limits of System Operating Voltages are provided strictly for voltage regulation purposes. These limits are not to be construed by Users as National Grid operating voltages at the Connection Points which shall be maintained as per instructions of SO.

OC 5.5.8. **Description of Voltage Control**

OC 5.5.8.1. The SO shall control system voltage in order to minimize system losses and cost of use of Ancillary Services. The SO shall determine and modify as appropriate, general procedures for its use in controlling Voltage on the Transmission System. The procedures shall be formulated having due regard to relevant economics of Transmission System operation and reliability. In particular, the Voltage Control shall take cognizance of daily, weekly and seasonal factors.

OC 5.5.8.2. The SO shall determine:

(a) suitable target Voltages in order to limit/control the effect of transmission capacitance;

(b) best utilization of dedicated Voltage Control facilities; and

(c) MVAR dynamic reserve requirements.

OC 5.5.8.3. Transmission System Voltages shall be continuously monitored by the SO. Appropriate Voltage operating points shall be determined by the SO, taking account of OC 5.5.8.1 and in particular of System conditions pertaining at the time of operation.

OC 5.5.8.4. The SO shall adjust System Voltages, using control facilities that are available so as to achieve the MVAR capacity necessary in order to operate Transmission System Voltages within the limits specified in Operation Code and retain a dynamic MVAR capability to deal with changing System conditions which result from changes in Demand or changes in transmission or generation configuration, whether as a result of control actions or faults.

OC 5.5.8.5. DISCOs and BPCs shall be responsible for the maintenance of power factor at 132 kV buses above 0.95 during steady-state operating conditions by installing appropriate power factor correction facilities within their Service Territories. DISCOs/BPCs shall not offer leading power factor to the Transmission System in any case.

OC 5.5.8.6. To avoid any doubt, there shall be no export of Reactive Power (MVAR) from bulk Transmission System to DISCOs/BPCs at 132 kV Connection Points or otherwise permitted by SO.

OC 5.5.9. **Methods of Voltage Control**

OC 5.5.9.1. Voltage control methods used by the SO include:

(a) User MVAR Demand/power factor correction;

(b) transformer tap-changing, cable switching, reactor and capacitor switching;

(c) dynamic voltage support including control modes of HVDC/ESUs (e.g. voltage control, reactive power control, power factor control modes).

(d) utilization of Generating Unit Reactive Power capability, both by means of AVR control and also MVAR Dispatch Instructions issued by the SO to Generators;

(e) utilization of Interconnector Reactive Power capability by means of suitably acting AVR/RPC control and/or MVAR Dispatch Instructions issued by the SO to Interconnector;

(f) tap-changing on Generator Transformers;

(g) switching out of transmission HV cables (and occasionally transmission lines) in order to reduce the capacitive contribution of the Transmission System.

OC 5.5.9.2. The excitation system of each Synchronous Generating Unit shall normally be operated under the control of a continuously acting AVR, which shall be set so as to maintain a constant terminal voltage. The Generator may not disable or restrict the operation of the AVR except in accordance with OC 5.5.9.6, in which event the Synchronous Generator shall notify the SO without delay.

OC 5.5.9.3. Each Non-Synchronous Generating Unit shall control the voltage at the Connection Point by means of a suitable continuously acting Reactive Power Controller (RPC)system. The voltage control mode shall be agreed under the relevant Agreement(s) and relevant settings shall be specified by SO.

OC 5.5.9.4. Each Interconnector shall control the voltage at the Grid Connection Point by means of a suitable continuously acting RPC. The voltage control mode shall be as per relevant Agreement(s). The Interconnector may not disable or restrict the operating of the RPC except in accordance with OC 5.5.9.6, in which event the Interconnector shall notify the SO without undue delay.

OC 5.5.9.5. Voltage Control may necessitate the modification of Generating Unit MW output, or Interconnector(s) Active Power transfers to or from the Transmission System.

OC 5.5.9.6. The Generator or Interconnector may only disable or restrict AVR action where:

(a) the action is essential for the safety of personnel and/or Plant; or

(b) in order to (acting in accordance with Prudent Utility Practice), secure the reliability of the Generating Unit or Interconnector; or

(c) the restriction is agreed between the SO and the Generator or Interconnector in advance.

OC 5.5.9.7. In case the SO either agrees to a restriction in AVR action or instructs such a restriction, the SO shall record the nature of the restriction, as well as the reason(s), time of occurrence, and the duration of the restriction.

OC 5.5.9.8. In the event of a Generating Unit not operating under AVR, unless instructed by SO, the SO may impose restrictions on the operation of the Generating Unit in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Generator to De-Energize, or not Energize/Synchronize the Generating Unit.

OC 5.5.9.9. In the event of an Interconnector not operating under AVR, the SO may impose restrictions on the operation of the Interconnector in accordance with Prudent Utility Practice, to the extent necessary to provide for safe and secure operation of the Transmission System and operation within prescribed standards, including where necessary instructing the Interconnector to De-Energize, or not connect/synchronize with the Interconnector.

OC 5.5.9.10. The SO shall, by means of Dispatch Instructions (as provided in SDC), instruct Generators and Interconnectors to adjust the Reactive Power output of Generating Units and Interconnectors, and the relevant provisions of SDC shall apply.

OC 5.5.9.11. The extent to which Voltage Control mechanisms can be utilized may be limited by System conditions and other limitations of Plant and Apparatus.

OC 5.5.9.12. On some occasions it shall be necessary to reschedule Generating Units or Interconnectors away from their desired output in order to achieve Transmission System Voltages within the limits specified in OC 5.5.7. However, the SO will resort to such rescheduling only to deal with emergencies or contingencies that threaten the Stability and Security of the Transmission System.

OC 5.5.10. **Emergency or Exceptional Voltage Control**

OC 5.5.10.1. Additional Voltage Control mechanisms may be utilized in the event of System Emergency Conditions. These shall include the following:

(a) Generators may be requested to operate Generating Units/Interconnectors at MVAR production or absorption levels outside their currently declared Technical Parameters. This will be done by agreement between the Generator/Interconnector and the SO and Generators/Interconnectors will not be penalized for non-compliance with this clause;

(b) the SO may also effect changes in System voltage by instructing, as a form of Dispatch Instruction, the Generators to carry out a tap-change on the main Generator transformer of several Generating Units simultaneously; and

(c) Demand Management may be used to prevent Voltage from contravening low Voltage limits (as further provided in OC 3).

OC 5.6. **Black Start**

OC 5.6.1. In order to recover the Transmission System from a Partial or Total Shutdown, it is necessary to have certain Generating Stations/ HVDC Stations (Black Start Stations) available which have the ability for at least one of their Generating Units/Converter Station(s) to Start-Up from Shutdown and to Energize a part of the System, Synchronize with the System, and Energize dead bus, upon instruction from the SO, without an external electrical Power supply.

OC 5.6.2. In order to maintain Security on the Transmission System at all times, Black Start Stations are required to comply with the provisions of this subsection.

OC 5.6.3. The Generating Units/ HVDC Stations with Black Start capability must provide frequency and voltage within the prescribed limits during line Energization and remote load pick up.

OC 5.6.4. The SO shall verify the actual performance of Black Start capability when actual system Blackout conditions occur.

OC 5.6.5. Generators/ HVDC Stations providing Black Start capability will also be required to provide voice and other communication facilities linked with the SO and capable of operating without an external AC Power supply for the period as specified by the SO in the relevant agreement.

OC 5.6.6. **Requirements of Black Start Stations**

OC 5.6.6.1. During a Black Start situation, instructions relating to Black Start Stations will be in the format required for instructions to Generating Units/ HVDC Stations in the Scheduling and Dispatch Code, and will recognize any differing Black Start operational capabilities (however termed) set out in the relevant System (Ancillary) Services Agreement in preference to the Declared operational capability as registered pursuant to the CC/PC. For the purposes of these instructions, the Black Start will be an emergency circumstance. For Generating Units/ HVDC Stations which are not Black Start Units, Dispatch Instructions will recognize each Unit's Declared operational capability as registered pursuant to the CC/PC.

OC 5.6.6.2. The Generator shall report to the SO all the required operational procedures to operate the Black Start Unit.

Response data for Frequency Changes

a) Actual Frequency Response Capability Profile; and

b) Response values at specific MW loading points in the range of 0-3 seconds, 3-10 seconds, and 10-30 seconds following the fall in frequency.

Primary Response to Frequency Fall

Primary Response (within 0 – 3 seconds, 3-10 seconds of frequency fall) values for a -0.5Hz up to all the loading points identified in OC 5.A.b.

Secondary Response to Frequency Fall

Secondary Response (within 10 – 30 seconds of frequency fall) values for a – 0.5Hz up to all the loading points identified in the OC 5.A.b.

High Response to Frequency Rise

High Response values for a +0.5Hz up to all the loading points as detailed in OC 5.A.b.

Generator, Governor and Droop Characteristics

Unit Control Options

Control of Load Demand

OC 6. **NETWORK CONTROL**

OC 6.1. **Introduction**

OC 6.1.1. In routine operation of the National Grid, in implementing the Transmission Outage Program, and in responding to Emergency and Fault situations on the Transmission System, the SO needs to carry out Control Actions which may from time to time affect the operations of Users or Security of supply to Users.

OC 6.1.2. The purpose of this OC 6 is to set out the actions which may be taken by the SO in controlling the National Grid, to set out the procedures whereby the SO shall inform Users, where practicable, as to network Control Actions which will or may be likely to significantly affect User's operations and to identify where the SO shall, insofar as reasonably practicable, consult with Users and take into consideration Users' reasonable requirements.

OC 6.1.3. All Transmission connected facilities/Apparatus shall be under the control of SO. Any switching operation or Control Action carried out by any User on Transmission System without prior instructions/authorization of SO shall be deemed as non-compliance and dealt as per NEPRA (Fines) Rules. In case a switching operation or Control Action is carried out by a User in Emergency, the action must be justified to the satisfaction of the SO.

OC 6.1.4. Each User shall also make their facilities/Apparatus connected below Transmission Voltage levels available to the SO for control when required. Instructions received by the SO regarding facilities/Apparatus connected below Transmission Voltage levels shall be binding on the Users and non-compliance shall be liable as per NEPRA (Fines) Rules.

OC 6.2. **Objective**

The objective of OC 6 is to:

(a) identify the Control Actions that may be taken by the SO and relevant Code Participants, so that the SO may carry out operation of the Transmission System and respond to Transmission System faults and emergencies.

(b) to establish procedures whereby the SO will:

(i) where practicable, inform Users who will be or are likely to be significantly affected by network Control Actions, of relevant details of intended Control Actions and the effect of those Control Actions;

(ii) consult with Users as appropriate in order to find out and take into consideration reasonable objections raised by Users so affected.

OC 6.3. **Scope**

The scope of this OC.6 applies to SO and the following Users:

(a) Generators connected to the Transmission System;

(b) Transmission Network Operators;

(c) DNOs (DISCOs);

(d) Bulk Power Consumers BPCs;

(e) Transmission Connected Consumers;

(f) Interconnectors.

(g) Small/Embedded Generators whether represented through some Aggregators or any other arrangement (if required by SO).

OC 6.4. **Network Control Actions**

OC 6.4.1. The SO needs to carry out Control Actions for a number of purposes, which include, but not limited to the following:

(a) Outages of network component and Apparatus for the purposes of maintenance, User Development, System Tests, protection testing and work by Users;

(b) Outages of Transmission System Plant and Apparatus due to suspected or potential faults and emergency repairs;

(c) Voltage Control;

(d) Managing network configuration to maintain power flows on the Transmission System within the levels consistent with the capabilities of the Transmission System Plant and Apparatus for System Security;

(e) Demand Control;

(f) Change of Control Modes, adjustment of Control Mode parameters and setting associated set-points, flow variations of HVDC in the Transmission System.

OC 6.4.2. Additionally, network switching may occur automatically and without advance warning due to operation of protection equipment in isolating or clearing faults on the National Grid.

OC 6.4.3. Automatic switching sequences may also be established to limit power flows or Voltage or Frequency deviations in the event of faults elsewhere on the System.

OC 6.4.4. This OC.6 also applies on Wheelers and third party entities contracted by Users for the purpose of operation and maintenance etc.

OC 6.5. **Transmission System Operating States**

OC 6.5.1. **Normal State**

The Transmission System shall be considered to be in the Normal State when:

(a) The Single Outage Contingency (N-1) Criterion is met;

(b) The Operating Reserves are in accordance with the values established as given in OC 5;

(c) The System Frequency is within the limits as specified in OC 5.4.4;

(d) The voltages at all transmission nodes are within the limits as specified in OC 5.5.7;

(e) The loading levels of all transmission lines and substation Equipment are within normal operating limits defined in OC 6.7;

(f) The Transmission System configuration is such that any potential fault current can be interrupted and the faulted Equipment can be isolated from the Transmission System.

OC 6.5.1.1. **Single Outage Contingency (N-1) Condition**

The N-1 Condition(s) consists of one of the following contingencies:

(a) Loss of a single-circuit transmission line, except those radial circuits which connect Loads using a single line or cable;

(b) Loss of one circuit of a double-circuit transmission line including the point-to-point connection of a Generator to the Transmission System;

(c) Loss of a single Transformer, except those which connect Loads using a single radial Transformer;

(d) Loss of a single pole of a bi-pole HVDC;

(e) Loss of a Generating Unit; and

(f) Loss of compensating devices, i.e., Capacitor/Reactor/SVC etc.

OC 6.5.1.2. **Single Outage (N-1) Criterion**

The Single Outage Contingency (N-1) Criterion is satisfied if, after a single Outage in the system specified in OC 6.5.1.1 occurs, the following rules are observed:

(a) There is no breach of the limiting values for operation voltage, as given in OC 5.5.7 and Frequency, as given in OC 5 that may endanger the Security of the Power System;

(b) No Equipment/transmission line loading has exceeded normal operating limits defined in OC 6.7;

(c) Interruptions of electric power supply to End-Users are avoided;

(d) Cascading Outage is avoided;

(e) There is no need to change or interrupt power transfers and generation Dispatch;

(f) The loss of Generating Unit stability is avoided.

OC 6.5.2. **Contingency State**

The Transmission System shall be considered to be in the Contingency State when any one of the following conditions exists:

(a) The Single Outage Contingency (N-1) Criterion is not met;

(b) The Operating Reserves are less than the values required to stabilize Frequency within the limits of OC 5;

(c) The voltages at the Connection Points are outside the limits of -5 to +8% of Nominal System Voltage during N-0 conditions but within the limits of ±10% of the Nominal Value;

(d) No Equipment/transmission line loading is above contingency operating limits (as described in Transmission Planning Criteria and Standards);

(e) A severe weather condition has occurred; or

(f) A law and order problem exists, which may pose a threat to Transmission System operations.

OC 6.5.3. **Emergency, Extreme Emergency and Restorative States**

OC 6.5.3.1. The Transmission System shall be considered to be in the Emergency State when either a Single Outage Contingency or a Multiple Outage Contingency (as described in Transmission Planning Criteria and Standards) has occurred without resulting in Total System Blackout, but any one of the following conditions exists:

(a) There is generation deficiency or Operating Reserve is zero;

(b) The Transmission System Voltage is outside the limits of ±10% of the Nominal Value; or

(c) The loading level of any transmission line or substation Equipment is outside contingency operating limits.

OC 6.5.3.2. The Transmission System shall be considered to be in the Extreme Emergency State when the corrective measures undertaken by the System Operator during an Emergency State failed to maintain System Security and resulted in Partial/Total Shutdown, Cascading Outages, Islanding, and/or National Grid voltage collapse.

OC 6.5.3.3. The Transmission System shall be considered to be in Restorative State when Generating Units, transmission lines, substation Equipment, and Loads are being Energized and Synchronized to restore the Stability of the system.

OC 6.6. **Transmission System Operating Cases**

OC 6.6.1. **Base Operating Case**

The System Operator shall operate the Grid in the Normal State. Each day the System Operator shall establish a generation schedule and shall dispatch generating units and transmission resources on an hour by hour basis as per the provisions of Scheduling and Dispatch sub-code. Dispatch Schedule shall provide adequate generation capacity to meet expected load, total operating reserves as per OC 5 and ancillary services requirements;

The Transmission system shall:

(a) not result in transmission congestion or voltage violations during the Normal State; and

(b) not violate contingency voltage limits or contingency loading limits on transmission lines or transformers or manifest stability problems during Normal and N-1 contingencies.

(c) be operated on the principles of SCED and Optimal Power Flow.

(d) be operated to minimize system operating costs (including generation, transmission costs) while maintain stability and reliability.

OC 6.6.2. **Contingency, Emergency, Extreme Emergency and Restorative Operating Cases**

OC 6.6.2.1. The System Operator shall have available and shall implement when required, generation re-dispatch plans and schedules for credible (N-1) contingency events (as described in Transmission Planning Criteria and Standards in PC) so that, if the system moves to a credible (N-1) contingency state, the System Operator can follow the re-dispatch and return the system to a Normal State.

OC 6.6.2.2. The System Operator shall have available and shall implement; Emergency operating procedures to deal with system emergencies.

OC 6.6.2.3. The System Operator shall have available and shall implement Remedial Actions able to neutralize or mitigate the consequences of Contingencies. Against each Contingency, the SO shall study the most effective countermeasure(s)that could be applied (manually or automatically) in real-time to prevent the Transmission System from being operated beyond contingency operating limits, and/or to avoid Cascading Outages resulting in a Partial/Total Shutdown, in case of incredible and extreme emergencies. These may include:

(a) Generating Unit Re-Dispatching;

(b) Usage of Voltage and/or power flow control on regulation Transformers;

(c) Network re-configuration;

(d) Demand Control; or

(e) Generating Unit Tripping

OC 6.6.2.4. The System Operator shall have available at all times and be in a position to implement, system restoration plans for the situation in which the system moves to an Islanded state or suffers Cascading Outages resulting in a Partial/Total Shutdown.

OC 6.6.2.5. TNOs and DNOs must be engaged to cope with the conditions of all credible and incredible contingencies.

OC 6.7. **Transmission System Loading Criteria**

OC 6.7.1. **Transmission Lines Loading Criteria**

OC 6.7.1.1. The Users shall establish loading limits for each transmission line. Loading limits shall be established according to Normal state (N-0) and (N-1) contingency states, as well as for Summer and Winter seasons, while keeping in view:

(a) Thermal loading limits of the conductors

(b) Maximum conductor temperature

(c) Minimum clearance to ground at mid-span under maximum load

(d) Allowable overload for 15 minutes (to cater for SO reaction time)

(e) Transient (power angle) stability and voltage stability limits

(f) Maximum allowable conductor temperature

(g) Wind velocity

(h) Aging Factor

OC 6.7.1.2. The loading limits established by Users must be consistent with applicable IEC, ANSI/IEEE standards such as:

(a) IEC-60287 for Underground cables

(b) IEEE Std. 738™-2012, IEC 60826 for Overhead conductors

OC 6.7.1.3. For reference, the following table summarizes overhead conductor's ambient conditions to calculate loading criteria of overhead lines.

Table OC.6-1 Ambient Conditions for Overhead Conductors[3]

Parameter	Summer Rating Bases	Winter Rating Bases
Maximum Conductor Temp.	90° C	90° C
Outdoor Ambient Temp. (avg.)	40°C	(see footnote)
Conductor Temp. Rise	(see footnote)	(see footnote)
Max. Emergency Conductor Temp.	None Allowed	None Allowed
Wind Velocity	0.61m/s	0.61m/s

OC 6.7.2. **Transformer Loading Criteria**

Power transformers including three phase and single-phase banks shall be loaded under normal and contingency conditions according to applicable IEC, ANSI/IEEE standards (such as IEC 60076-7:2005) or as specified by the respective manufacturers. Also, pre-load conditions shall be taken into account to determine loading limits in real time.

OC 6.7.3. **Transmission System Components Loading Criteria**

Transmission System components listed below, shall be loaded under Normal and Contingency conditions according to applicable IEC, ANSI/IEEE standards or as specified by the respective manufacturers.

[3]Conductor Temperature Rise shall be calculated based on the Outdoor Ambient Temperature (average used for each respective Province). Lower or higher Outdoor Ambient Temperature (average) within a Province different from the values stated in above table may be considered if the variation in such temperature is significant, depending upon the location.

Notes on Table OC.6-1:

(a) Summer Months = April through October

(b) Winter Months = November through March

(c) Emergency ratings are limited to (8) hours of continuous operation. Conductors shall not be operated above 100° C conductor temperature for more than 960 cumulative hours.

(d) The following average temperature of Winter shall be used for the respective provinces:

(i) Lahore (Punjab) 9.3° C

(ii) Peshawar (Khyber Pakhtunkhwa) 5.3° C

(iii) Quetta (Baluchistan) -1.7° C

(iv) Karachi (Sindh) 13° C

(a) Circuit breakers

(b) Current Transformers

(c) Circuit switchers

(d) Potential transformers

(e) Capacitors

(f) Wave traps

(g) Shunt reactors

(h) Substation power buses

(i) Disconnect switches

(j) Substation power cables

OC 6.8. **Notification to Users of Network Control**

OC 6.8.1. All network Control Actions carried out on the Transmission System have the potential in a given set of circumstances to affect Users. It is not practicable to attempt to inform Users of every Control Action and in most cases, the information will not be of any material value to the User as the User will not invoke any specific action as a result of receipt of the information.

OC 6.8.2. Where it is identified and agreed, in accordance with the terms of the Connection Agreements and/ or Operating Agreements, between the SO and a User that a specific Control Action (usually an action affecting the Transmission System configuration) has an Operational Effect on a User and that there is merit in notifying the User in advance of the Control Action, then the SO will notify the User of the Control Action (if planned and where time permits), in accordance with any standing agreement that may be agreed with the User.

OC 6.8.3. Typical examples of Actions notified in accordance with OC. 6.8 may include instructions to the Users of a significant reduction in supply security to a Connection Point (such as the Outage of one of two transmission connections), where the Users may arrange standby feeding arrangements at lower Voltages and/or activate embedded Generating units and/or connect Reactive Compensation Equipment and/or run in-house Generating Units;

OC 6.8.4. Where it is necessary to carry out urgent switching or other network Control Actions resulting from a System condition or fault, then it may not be possible for the SO to inform Users in advance of the switching or other Control Actions. The SO shall endeavor to inform Users where time permits, but this shall not delay timely implementation of Control Actions as required. Where the SO is unable to inform Users prior to the Control Actions, then the provisions of OC. 6.9 shall apply.

OC 6.9. **Control Under Fault or Emergency Conditions**

OC 6.9.1. In the event of a System fault or protection operation or other automatic operation, it will not be possible to invoke standing procedures in accordance with OC. 6.8 prior to the occurrence of the Control Action.

OC 6.9.2. In the circumstances referred to in OC. 6.9.1 or in the event that the SO needs to implement Control Actions urgently and without informing Users, then unless the situation is of a temporary nature and has been rectified to normal, the SO shall inform Users of the occurrence of the actions.

OC 6.9.3. The SO shall also inform Users as to the likely duration of the condition and shall update this prognosis as appropriate. The SO shall additionally inform Users when the condition has ended.

OC 6.9.4. Emergency Assistance to and from Interconnectors will be detailed in the relevant Agreement(s). An Interconnector may request that the SO take any available action to increase the Active Power transferred into its External System, or reduce the Active Power transferred into the Transmission System. Such request will be met by the SO only if this does not require a reduction of Demand on the Transmission System, or lead to a reduction in security of the Transmission System.

OC 6.10. **Termination (disconnection and reconnection) of User Facility, Plant and Apparatus**

Disconnection of a User's Plant and Apparatus may be effected at any time and from time to time, if and to the extent that the SO considers it necessary for safe and secure operation of the Transmission System within prescribed standards. The principles and procedure described below shall be followed to disconnect/re-connect it with the Transmission System.

OC 6.10.1. **Voluntary disconnection**

OC 6.10.1.1. Any User intending to de-rate, close, retire or withdraw from service or otherwise cease to maintain any Generating Unit(s) or VRE plants or ESUs or any Apparatus/Equipment shall give the SO at least thirty-six (36) calendar months' notice of such action.

OC 6.10.1.2. However, it should be ensured that disconnection and reconnection procedures are made an integral part of the Connection Agreement.

OC 6.10.1.3. Before taking any decision for disconnection of the equipment of the facility of the User, the SO shall ensure that such disconnection/de-rating will not have any adverse impact on the Transmission System Stability, Reliability, or Quality of Supply.

OC 6.10.1.4. All the costs incurred by any User for the de-rating/ disconnection of equipment or facility from Transmission System will be borne by the User seeking the de-rating/disconnection as per the Commercial Code/Connection Agreement.

OC 6.10.2. **Involuntary disconnection**

The SO may disconnect (through any action) Equipment, Apparatus, or the Facility of a User without any compensation to the relevant User, if:

(a) the User is not operating its facility in accordance with the Connection Agreement or in accordance with the recommended requirements of the Grid Code or relevant licensee, and other applicable documents;

(b) during emergencies, the User's facility must be disconnected in an orderly manner or as indicated in the Connection Agreement, such that the security and integrity of the System is not jeopardized;

(c) there is risk to the safety of personnel;

(d) there is risk to the Transmission System or any User's Plant or Apparatus;

(e) there is risk of Transmission System elements to become loaded beyond their emergency limits;

(f) Voltage excursions on the Transmission System outside the ranges specified in OC.5.5.7;

(g) There is need for Demand Management as described in OC.3;

(h) A User exhibits behavior causing sustained operation outside the normal Transmission System operating Frequency range;

(i) there is any action or inaction which places the SO in breach of any legal or statutory or regulatory obligation.

OC 6.10.3. **Reconnection of equipment or facility**

The System Operator shall permit the reconnection of the User's facility, equipment, and apparatus after confirming that the User has rectified all such circumstances, which were the cause of disconnection; and the SO has agreed and is satisfied with the corrected status of the Users facility. All the cost for reconnection of the User's facility which was disconnected shall be borne by the relevant User. The facilities, which were disconnected due to emergencies, must be reconnected as soon as the causes of emergencies were rectified and the Transmission System has returned to normal state.

OC 6.11. **Power System Stability and Security Coordination**

OC 6.11.1. The System Operator shall periodically carry out necessary Transmission System studies, simulations and tests (e.g. fast fault current injection, fault ride through capability, power oscillations damping control etc.) for expected system event scenarios (e.g. major outages of equipment, HVDC pole(s) failure etc.) that could lead to transient instability (unsatisfactory system dynamic performance and loss of angular stability), voltage instability, small signal instability and/or lack of power system oscillation damping.

OC 6.11.2. The System Operator shall maintain and be able and ready to implement, when required, standard operating procedures and Defense Plans (including manual control actions, cross-trip schemes, Stability Control System strategy, Remedial Action Schemes), designed in coordination with Users, to mitigate the extent of disturbance resulting from a system event, including the following:

(a) Permanent three-phase fault on any Transmission Equipment/Apparatus.

(b) Busbar section fault

(c) Permanent line fault with automatic reclosing to the fault

(d) Double circuit fault on both branches of a double circuit line

(e) Generator trip

(f) Interconnector trip

(g) HVDC pole(s) trip/block

OC 6.11.3. The studies may include (as the situation or case may demand) load flow studies, short-circuit studies, transient Stability studies, steady state Stability studies, dynamic performance studies, voltage Stability studies, electromagnetic transient studies, and Reliability studies, etc.

OC 6.11.4. SO shall also prepare plan for tuning of Power System Stabilizers of Generators which shall be implemented by respective Generators. PSS tuning shall be carried out as per the plan developed by SO and should have good local as well as system-level damping performance.

OC 6.11.5. All the Users shall be responsible to provide accurate and consistent technical data and simulation models to the SO, as when required, in order to enable the SO to carry out above mentioned studies.

OC 7. **HVDC OPERATION AND PERFORMANCE**

OC 7.1. **Introduction**

OC 7.1.1. Requirements related to design, performance, operational planning, communications, dispatch and operation of HVDC systems is already covered throughout the Grid Code as Transmission Network Operator (embedded HVDC), Special Purpose Transmission Line and/or Interconnector. However, for avoidance of doubt, details of operation and performance of HVDC systems are further elaborated in this OC.7.

OC 7.1.2. User-specific details regarding connection, design, operation, performance and communication with HVDC systems shall be as per relevant Agreement(s) and Standard Operating Principles, agreed with the SO.

OC 7.1.3. All DC yard main circuit equipment, converter transformer, converter valve, AC filter yard main circuit equipment, AC yard main circuit equipment of all voltage level, shall be under the exclusive control of SO, except auxiliary service equipment at 11kV or below.

OC 7.1.4. Any switching operation or Control Action carried out by any User on Transmission System without prior instructions of SO shall be deemed as serious non-compliance which shall be dealt as per Commercial Code or NEPRA Fine Rules. In case a switching operation or Control Action is carried out by a User in emergency, the action must be reported immediately and justified to the satisfaction of the SO.

OC 7.1.5. Each User shall also make their facilities/Apparatus connected below Transmission Voltage levels available to the SO for control when required. Instructions received by the SO regarding facilities/Apparatus connected below Transmission Voltage levels shall be binding on the Users and non-compliance shall be liable as per Commercial Code or NEPRA Fine Rules.

OC 7.2. **Objectives**

The objective of OC.7 is to:

(a) further elaborate operation of HVDC systems;

(b) identify the Control Actions that may be taken by the SO, so that the SO may carry out operation of the HVDC Transmission System and respond to HVDC Transmission System faults and emergencies.

(c) to establish requirements, and roles and responsibilities for operation of HVDC systems;

(d) establish procedures for non-compliance by a User.

OC 7.3. **Scope**

The scope of this OC.7 applies to SO and the following Users:

(a) Transmission Network Operators including SPTLs (embedded HVDC);

(b) Interconnectors.

OC 7.4. **HVDC Control Actions**

OC 7.4.1. The SO needs to carry out operational Control Actions on HVDC Systems for a number of purposes, which include:

(a) Start/deblock, and stop/block operation of HVDC pole.

(b) Change operation mode of HVDC Poles. (Pole Current Control/Pole Power Control/Bipole Power Control)

(c) Change of HVDC equipment status. (Connect/Isolate Pole, Metallic return/Ground return switching)

(d) Change of DC power flow direction.

(e) Change of DC pole bus voltage (Normal, Reduced).

(f) Start or stop operation of reactive power equipment at all voltage levels.

(g) Start or stop operation of transmission line connected with Converter Stations.

(h) Change of Master Station and Slave Station.

(i) Change of Bipole Power Order, DC pole power order or DC pole current order.

(j) Control mode of reactive HVDC power.

(k) Open line test (OLT).

(l) Change of AC filter equipment status.

(m) Shift of control location between Converter Stations and SO.

(n) Black Start operation (VSC based HVDC), where available.

OC 7.4.2. Additionally, network switching may occur automatically and without advance warning due to operation of protection equipment in isolating or clearing faults on the National Grid.

OC 7.4.3. Automatic switching sequences may also be established to limit power flows or Voltage or Frequency deviations in the event of faults elsewhere on the System.

OC 7.4.4. This OC.7 also applies on third party entities contracted by Users for the purpose of operation and maintenance etc.

OC 7.5. **HVDC Transmission System Operation**

OC 7.5.1. The HVDC system shall at all times be operated in harmony with in such a way as to achieve the best overall performance of the integrated AC and HVDC Transmission System.

OC 7.5.2. SO shall, with its best endeavor, avoid any disturbances from the AC system outside Converter Stations which interfacing with the HVDC System may results in fluctuation of the HVDC transmission power, consequences of such disturbance shall be dealt with in accordance with relevant Agreement(s).

OC 7.5.3. SO shall provide, as far as possible, necessary conditions such as enough Short Circuit Ratio/Level to ensure the smooth operation of the HVDC Transmission System in according with Technical Parameters and relevant Agreement(s).

OC 7.5.4. All Active overload capability and Reactive capability and other inherent capabilities of the HVDC system shall at all times be available to support the AC Transmission System in the event of AC system contingency as per the Technical Parameters of the HVDC system.

OC 7.5.5. The HVDC system shall meet or exceed the withstand capability and ride-through requirements for off-frequency and off-voltage operation as specified in this Grid Code and/or relevant Agreement(s).

OC 7.5.6. Where an HVDC system is required to have the capability to provide fast fault current at a Connection Point in case of symmetrical (3-phase) faults, the SO, in coordination with the relevant User, shall specify the following:

(a) when a voltage deviation is to be determined as well as the end of the voltage deviation

(b) the characteristics of the fast fault current and the timing and accuracy of the fast fault current, which may include several stages.

(c) The SO, in coordination the relevant User, may specify a requirement for asymmetrical current injection in the case of asymmetrical (1-phase or 2-phase) faults.

OC 7.5.7. The HVDC protections shall include protections for AC system protection from over and under voltage as well as over and under frequency, in the event that AC and HVDC systems are unable to restore the system to within operational limits of the withstand characteristic.

OC 7.5.8. 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 a planned or unplanned change in the HVDC system or AC network to which it is connected. Any information on the resilience of the HVDC system to AC system disturbances shall not be withheld.

OC 7.5.9. Fast Generator and/or load tripping (SCS) strategies shall be developed and provided as necessary, to avoid angular instability for mono/bipole blocking.

OC 7.5.10. However, necessary sufficient overload capability shall be provided in the second pole of a bipole to avoid generator/load tripping for a monopolar block, as far as possible.

OC 7.5.11. The protection of the HVDC system shall be coordinated with the protection systems of the AC system components so that the HVDC can continue to operate and shall not trip before other AC system protection events including:

(a) Generator over-voltage and under-voltage trips,

(b) Generator over-frequency and under-frequency trips

(c) AC line breaker failure trips

(d) Impedance protection Zone 2 tripping without communications

(e) AC line trip and reclose (including single pole trip and reclose)

OC 7.5.12. A strategy shall be developed by the SO in coordination with User(s) to attempt to clear the DC line faults in symmetric monopole and restart the pole as early as possible.

OC 7.5.13. The HVDC control system shall be resistant to repetitive commutation failure and shall recover promptly in case of such faults.

OC 7.5.14. The HVDC controls shall not cause negative damping of sub-synchronous oscillations of Generators or inter-area oscillations. HVDC Transmission System shall also not interact with Non-Synchronous Generators to cause Sub-Synchronous Control Interaction (SSCI).

OC 7.5.15. As long as the HVDC Transmission System is operating in monopole mode or bipole mode, the maintenance of any main circuit equipment or secondary circuit equipment of the bipolar neutral bus is prohibited. A complete shutdown of both poles of the HVDC system is needed to perform maintenance of a Bipole Neutral bus.

OC 7.5.16. SO can take/release the remote control of HVDC system anytime with prior intimation to the User, and User shall follow the instructions of SO.

OC 7.5.17. Exchange of Reactive Power under U-control, Q-Control or Power Factor Control modes shall be at discretion of SO as per System conditions or as per relevant Agreement(s).

OC 7.5.18. The Reactive Power variation caused by the Reactive Power Control mode of the HVDC Converter Station, shall not result in a voltage step exceeding the allowed value at the Connection Point.

OC 7.5.19. Similarly, exchange of Active Power under different control modes and supplementary control functions shall be at discretion of SO as per System conditions or as per relevant Agreement(s).

OC 7.5.20. The relevant parameters and set-points for operation of HVDC system, including ramp rates, dead bands, auto/manual mode etc. shall be adjusted by SO as per System conditions, Technical Parameters and/or relevant Agreement(s).

OC 7.6. **Compliance of SO Instructions**

OC 7.6.1. Users shall follow the instructions from SO without compromise. The procedure for non-compliance shall be as described in OC.11.

OC 7.6.2. Users shall immediately inform about the possible implication of the instructions issued by SO that may lead to:

(a) possibility of posing hazards or threat to staff or personnel of operation and maintenance.

(b) possibility of overloading or damage to equipment at Converter Stations/HVDC Transmission Line.

(c) possibility of causing disturbance in Transmission System.

OC 7.6.3. In case a User does not follow any SO Instructions due to any of the reasons expressed in OC 7.6.2 above, User shall immediately inform and clarify to SO at the earliest regarding the non-conformity.

OC 7.6.4. In case of any disputation, the procedure agreed between SO and User shall be applicable as per relevant Agreement(s).

OC 8. **OPERATIONAL LIAISON**

OC 8.1. **Introduction**

OC.8 sets out the requirements for the exchange of information relating to Operations, Events and Significant Incidents on the Transmission System that may have, or have had, an Operational Effect on the Transmission System or systems of other Users.

OC 8.2. **Objectives**

OC 8.2.1. The objectives of OC.8 are to:

(a) provide a coordination mechanism between Code Participants to ensure that communication of Operations, Events, and Significant Incidents is timely and effective, to assess their potential consequences and take appropriate actions to minimize their adverse impacts on the Transmission system;

(b) to specify the procedure for investigation and reporting of Significant Incidents on the Transmission system that materially affected the Quality of service;

OC 8.3. **Scope**

OC8 applies to the SO and to Users, which term in OC.8 means:

(a) Generators (CDGUs or Embedded);

(b) Interconnectors;

(c) TNOs/DNOs;

(d) DISCOs/Suppliers/BPCs;

(e) Transmission Connected Consumers

OC 8.4. **Notification of Operations and Events**

OC 8.4.1. The SO will notify the User (except as provided in OC 8.4.3) of Operations/Events on the Transmission system, which will have (or may have), in the reasonable opinion of the SO, an Operational Effect on the User. Except as agreed with the SO, the User shall not pass on the information contained in a notification to it from the SO under this OC8 to any other person.

OC 8.4.2. The User shall notify the SO of any Operations/Events on the User's System which will have (or may have) an Operational Effect on the Transmission system. The SO may use this information to notify any other User(s) on whose System(s) the Operation/Event will have, or may have, in the opinion of the SO, an Operational Effect, in accordance with this OC.8.

OC 8.4.3. In circumstances where it is not possible to invoke standing procedures prior to the occurrence of an Operation or in the event that the SO needs to implement Operations urgently and without informing the User then, unless the situation is of a temporary nature, the SO shall inform the User of the occurrence of the Operations without undue delay. The SO shall also inform the User as to the likely duration of the condition and shall update this prognosis as appropriate. The SO shall additionally inform the User as soon as possible when the condition has ended.

OC 8.4.4. Notwithstanding the general requirements to notify set out in this OC8, the SO and Users shall agree to review from time to time which Operations and Events are required to be notified.

OC 8.4.5. **Form of Notification of an Operation/Event**

OC 8.4.5.1. A notification (and any response to any questions asked under OC.8.4.5.3), of an Operation/Event shall be of sufficient detail to describe the Operation/Event and to enable the recipient of the notification reasonably to consider and assess the implications and risks arising.

OC 8.4.5.2. A notification will include the name (and job title) of the individual reporting the Operation/Event on behalf of the SO or the User, as the case may be.

OC 8.4.5.3. The recipient of the notification may ask questions to clarify the notification and the giver of the notification will, insofar as he is able, answer any questions raised.

OC 8.4.5.4. The notification shall be given in writing whenever possible before carrying out an Operation. If there is insufficient time before the Operation is scheduled to take place for notification to be given in writing, then the notification shall be given verbally and if either the User or the SO requests, it shall be submitted in writing.

OC 8.4.5.5. A notification (via an acceptable medium) under this section shall be given as far advance as practicable to allow the recipient to consider and assess the implications and risks arising.

OC 8.4.5.6. A System Alert, further defined in OC.12, may be issued by the SO (subsequently to be confirmed in writing) to Users who may be affected when the SO realizes that there is a risk of widespread and serious disturbance to the whole, or a part of, the Transmission system.

OC 8.5. **Not Used**

OC 8.6. **Significant Incidents**

Where a User notifies the SO pursuant to this section of an Event which the SO considers has had or may have had a significant effect on the Transmission System, the SO will require the User to report that Event in writing in accordance with the provisions of this section. Such Event will be termed as "Significant Incident" and may include, but not limited to, the following:

(a) Voltage outside operational limits;

(b) System frequency outside statutory limits;

(c) Load Disconnection;

(d) islanding conditions;

(e) System instability

OC 8.7. **Significant Incident Reporting Procedure**

OC 8.7.1. A Significant Incident Notice shall be issued by the SO or a User, as the case may be, as soon as possible (but not later than 24 hours) after the occurrence of the Significant Incident, and shall identify the following, if possible:

(a) date, time, and location of the Incident;

(b) brief description of the Incident;

(c) expected impact;

(d) expected time to restore; and

(e) the cause.

OC 8.7.2. The SO shall investigate any Significant Incident that materially affected the Transmission System or the system of any another User. A preliminary Significant Incident Report shall be available within fifteen (15) working days and shall include the following:

(a) factual description of the Event/ incident root causes;

(b) the pre-incident conditions;

(c) the operational conditions of the Transmission System at the time of incident;

(d) the corrective and mitigating actions implemented after the event/ incident.

OC 8.7.3. A final Significant Incident Report shall be available within two (2) months of the incident which shall include:

(a) root causes of the incident;

(b) estimated energy not served;

(c) proposal for corrective measures/ mitigation actions to increase the System reliability.

OC 8.7.4. The SO shall initiate and coordinate such an investigation, arrange for the writing of the report, and involve all Affected Users through a cross-functional team having members of relevant stakeholders or third party as deemed appropriate. The Users shall make all relevant information (such as User's own investigative report, disturbance recorder/event logger details, pre- and post-event operational data, restoration sequence details, relay indications for all elements affected, Remedial Action plan, and/or any non-compliance of Grid Code observed during the Incident) available to the SO and participate in the investigation where reasonably required. The SO shall make the report available (if requested) to any User within the confidentiality constraints.

OC 8.8. **Monthly and Annual Operations/Events Reports**

OC 8.8.1. The Users shall prepare and submit to the SO monthly Operations Reports on Grid Operations and Events. These reports shall include an evaluation of the Operations, Events, Significant Incidents, and any other problems that occurred on the Transmission System during the previous month, the measures undertaken by the Users to address them, and the recommendations to prevent their recurrence in the future.

OC 8.8.2. The Users shall prepare and submit to the SO quarterly and annual Operations Reports also. These reports shall include the Operations, Events, and Significant Incidents that had a Material Effect on the Transmission System or the System of any User (as the case may be) during the past quarter or the year.

Report of a Significant Incident on System

Information (where relevant) to be given

1. Time and date of Significant Incident on System
2. Location
3. Plant/Apparatus involved
4. Description of the Significant Incident
5. Demand/Generation lost
6. Generating Unit Frequency
7. Generating Unit MVAR performance
8. Estimated duration of non-availability of Power Plant or that of Demand interruption.

OC 9. **OPERATIONAL COMMUNICATION AND DATA RETENTION**

OC 9.1. **Introduction**

To ensure proper monitoring, operation and control of the National Grid, standard, reliable and adequate communication facilities and procedures between SO and the Users are essential. This OC specifies the details of the communication facilities required between the SO and Users and also establishes the procedures to be used by the SO and Users to ensure timely exchange of information to enable the SO to discharge its obligations regarding the operation of the National Grid.

OC 9.2. **Objective**

OC 9.2.1. The objectives of this OC 9 is:

(a) to establish proper contact locations for the SO and other Users;

(b) to detail real time monitoring, control and communication facilities which are required to be installed and maintained between the SO and the Users;

(c) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code and/or relevant Agreement(s)) for exchange of operational information between the SO and the Users;

(d) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code and/or relevant Agreement(s)) for the authorization of the SO and the User personnel to act on behalf of their respective entities in the communication of operational information between the SO and the User.

(e) to establish the general procedures (notwithstanding any specific procedures which may be established in other sections of this Grid Code) for the retention of data.

OC 9.2.2. This OC.9 covers the general procedures for all forms of communication of operational information between the SO and Users, other than the pre-connection communication that is dealt with in the Connection Code. Data relating to commercial (Energy) metering is specifically not covered by this OC.9.

OC 9.3. **Scope**

The provisions of OC.9 shall apply to the SO and Users as listed below:

(a) Generators in respect of their generating units and transmission stations;

(b) Transmission Network Operators (in respect of their transmission stations and communication services)

(c) Distribution Network Operators (in respect of their substations and communication services)

(d) Demand Side Units; (DISCOs, Suppliers, BPCs);

(e) Transmission Connected Consumers;

(f) Interconnectors;

(g) ESUs;

(h) Small / Embedded generators whether represented through Aggregator or otherwise.

OC 9.4. **Contact Locations and their Adequacy**

OC 9.4.1. **The System Operator Contact Locations**

OC 9.4.1.1. Other than where specifically provided for under Section OC.9.4.1.2 or in other sections of the Grid Code, the contact location within the SO for communication on matters pertaining to the real time operation of the National Grid shall be the designated Control Centre(s) of System Operator (e.g. Main Control Centre (MCC), Backup Control Centre (BCC), Emergency Control Centre (ECC) etc.).

OC 9.4.1.2. The SO will, from time to time, notify to Users the relevant points of contact in the SO (and their contact details) and any changes to such points of contact and/or details for the purposes of each section of this Grid Code (including, where appropriate, for specific purposes under each section), and the User shall, as required, contact the relevant notified points of contact.

OC 9.4.1.3. The SO shall from time to time distribute to each User an organizational chart and list of personnel and contact numbers (consistent with the notification given under Section OC.9.4.1.2) in order to assist the User in communicating with the SO.

OC 9.4.2. **The Users Contact Locations**

OC 9.4.2.1. The User contact locations and personnel (including their electronic mailing addresses, if any) referred to in this Section OC.9.4.2 shall be notified by the User to the SO prior to connection and thereafter updated as appropriate.

OC 9.4.2.2. Each User is required to provide a Control Facility. The Users shall ensure acting in accordance with Good Industry Practice that the Control Facility is staffed at appropriate qualified and trained level at all times.

OC 9.4.2.3. In case of Generator Aggregators and Suppliers, a single Control Facility and contact personnel is required. The Control Facility of all Users shall be staffed by a Responsible Operator(s) who shall respond to communications from the SO without undue delay, except where otherwise provided for by agreement between the User and the SO (such agreement not to be unreasonably withheld). All the communications (other than relating to the submission of data and notices) between the SO and the User shall take place between the SO and Responsible Operator(s) of User. The Responsible Operator(s) shall be of suitable experience and training and are authorized to perform the following functions on behalf of the User.

(a) to accept and execute Dispatch Instructions;

(b) to receive and acknowledge receipt of instructions from SO, for amongst other matters, operation outside the Declared values of Availability, Ancillary Service capability, or Operating Characteristics of the User Plant and Apparatus during System Emergency Conditions.

OC 9.4.2.4. At any point in time, a single person shall be designated by the User and notified to the SO as the Responsible Manager. The Responsible Manager shall be responsible for dealing with the SO on matters other than as provided for in OC.9.4.2.3. In the event that the Responsible Manager is not a person on duty at the Control Facility, then the Responsible Manager must be capable of being contacted from the Control Facility at all times, and in the event that the SO issues an instruction to the Control Facility requiring the Responsible Manager to contact the System Operator, the Responsible Manager shall comply with the request without undue delay and in any case within 10 minutes of the instruction.

OC 9.4.2.5. The Responsible Manager shall be authorized by the User to perform the following functions on behalf of the User:

(a) to make estimates in accordance with Good Industry Practice as to the Availability, Ancillary Service capability and Operating Characteristics of the User facility;

(b) to submit and revise an Availability Notice and other data related to the User facility as under SDC1

(c) to communicate with respect to issues regarding Outages of User Plant and Apparatus as under OC4

OC 9.4.2.6. The User may, from time to time, notify a replacement contact location and personnel which meets the foregoing requirements.

OC 9.5. **Communication Facilities**

OC 9.5.1. The minimum communications facilities which are to be installed and maintained between the SO and the Users are defined in this Section OC.9.5.

OC 9.5.2. All equipment to be provided by Users under this Section OC.9.5 shall comply with the applicable International Telecommunications Union (ITU) and International Electro-Technical Commission (IEC) standards for SCADA and communications equipment and shall meet such standards as notified by the SO and TNOs/DNOs.

OC 9.5.3. **Supervisory Control and Data Acquisition System (SCADA)**

OC 9.5.3.1. SCADA System will be used by SO for real time monitoring and control of the National Grid during normal, contingency, emergency, extreme emergency and restorative conditions.

OC 9.5.3.2. All Users shall install remote telemetry equipment and associated auxiliary components, at their respective facilities for exchanging real time data and control signals with the SO's SCADA System through standard IEC protocols. The cost of integration of Users telemetry equipment (Remote Telemetry Units RTUs, SAS/PCS/DCS Gateways etc.) with SO's SCADA System, both at Main and Backup Control Centre(s), will be borne by the respective User.

OC 9.5.3.3. Remote telemetry equipment, which may include RTU, PCS/DCS/SAS Gateways, IEDs or any other such equipment/ facility (to be installed with prior approval of the SO), shall be capable of exchanging real time data and control signals with the SO's SCADA System through standard IEC data communication protocols.

OC 9.5.3.4. The remote telemetry equipment of Users shall be compatible with the SO SCADA master station protocol requirements and must provide redundant and standard IEC interfaces for data connectivity with Main and Backup Control Centre(s) of SO. It shall also be capable of time stamping of signals and events on minimum resolution of 1 millisecond or finer resolution as specified by the SO.

OC 9.5.3.5. All Users shall maintain the remote telemetry, networking and communication equipment at their respective sites and shall be responsible to expand and upgrade the equipment as and when required by the SO. All such equipment shall have at least 50 % spare capacity for future expansion. The cost of such expansion and upgradation of User's remote telemetry system along with its auxiliary components and its integration with SO SCADA System will be borne by the respective User.

OC 9.5.3.6. SCADA Signals Interface Cabinets/Cubicles (SIC) shall be installed in the User's Control Centre/Control Facility, for the transmission of signals and indications to and from the SO. The provision and maintenance of the wiring and signaling from the User's Plant and Equipment to the interface cabinets shall be the responsibility of the User.

OC 9.5.3.7. The signals and indications which must be provided by Users for transmission by remote telemetry equipment to the SO are the signals and indications referred to under Connection Code CC.9 Appendix-G together with such other information as the SO may require from time to time by notice to Users.

OC 9.5.3.8. In case of Generators, signals and indications must be provided to the SO on individual Generating Unit basis.

OC 9.5.3.9. In cases where the Users are equipped with or intending to develop their own SCADA System or any other telemetry system such as Automatic Meter Reading (AMR), Smart/ Secured Metering System (SMS), Web portals based telemetry, Awareness System etc., covering all or part of its transmission/distribution system or Plant/Equipment and the SO considers necessary to receive the information collected into such system, data communication/ exchange through standard IEC protocols between the SO's and User's SCADA or other such system, as the case may be, shall be established. In general, sharing of such data/information/telemetry facility under OC 9.5.3.9 shall not be withheld by the Users.

OC 9.5.3.10. If any change occurs in the User's Plant and Equipment, User shall be responsible to incorporate all such changes in the remote telemetry equipment.

OC 9.5.3.11. The SO shall have the capability to deactivate and reactivate the scanning of a given RTU, as well as the capability of monitoring the availability of all RTUs from a central location.

OC 9.5.3.12. In the absence (temporary) of any such remote telemetry system or during development phase of such remote telemetry facilities, Users shall provide the real time data/ information related to its plant and equipment to SO through interim alternate arrangements with prior approval of SO.

OC 9.5.4. **Communication System**

OC 9.5.4.1. The TNOs/DNOs shall provide at least dual, high-speed, network wide and dedicated communication facilities installed on its system, to provide for the communication between SO's designated Control Center(s) and the Users sites. The communication systems shall provide redundant channels for direct telephone, facsimile and data links between the SO (Main and Back Up Control Centers) and User facilities.

OC 9.5.4.2. The TNOs/DNOs shall provide the communication system for the network in its Service Territory and extend the facility to the Connection Point of the User.

OC 9.5.4.3. The TNOs/DNOs shall also install, operate and maintain a redundant communication interface, compatible with the SO's SCADA System, at the SO designated Control Centers (Main and Back up Control Centers).

OC 9.5.4.4. TNOs/DNOs shall provide its network for all communication services (e.g. voice, facsimile, data etc.) between Users and SO (Main and Backup) Control Centers.

OC 9.5.4.5. The SO, TNOs/DNOs and other Users shall operate, maintain, expand and upgrade from time to time, their respective SCADA Systems, with dedicated supporting communication system and remote telemetry equipment, as it corresponds to.

OC 9.5.4.6. Not Used

OC 9.5.4.7. The TNOs/DNOs shall provide all Users, specifications for remote telemetry equipment, communication system requirements and protocols, and technical assistance required to connect Users' facilities with the SO SCADA system.

OC 9.5.4.8. A User will be responsible for installation, upgrade and maintenance of their respective remote telemetry equipment and associated communication equipment up to the Connection Point.

OC 9.5.4.9. TNOs/DNOs shall also establish communication interlinks between their networks to provide connectivity between Users facilities and SO's designated Control Centre(s).

OC 9.5.4.10. The TNOs/DNOs communication facility shall also be used for communicating with TNOs/DNOs work crews and substation personnel.

OC 9.5.4.11. An electronic recording device(s) shall be provided at the SO control centers to record all dispatch transactions and communication with the Users Control Centers/Control Facilities. Such records shall be kept until at least five (5) years and will be used to deal with any dispute should such disputed arise during implementation.

OC 9.5.4.12. TNOs/DNOs shall also install remote telemetry equipment (RTU/Gateway etc.) at their respective substations.

OC 9.5.4.13. All Users shall provide an SO approved dedicated voice communication service (e.g. telephone hotlines based on IP/ PLCC/ Satellite etc.) to provide both primary and alternate communication links between the SO and the operator controlling the User facility.

OC 9.5.4.14. Not Used

OC 9.5.4.15. The remote telemetry and communication equipment shall also provide signals and indications for fault indications.

OC 9.5.5. **Computer Equipment**

Each User shall comply with the SO requirements and provide dedicated and appropriate computer and data networking equipment to allow data exchange such as electronic mail, dispatch instructions etc. between the SO and the User. The equipment shall only be used by the User for operational communications with the SO.

OC 9.5.6. **Telephone and Facsimile**

OC 9.5.6.1. Each User shall be responsible for the provision and maintenance (at the cost of the User) of telephone and facsimile equipment as required by this Section OC 9.5.6.

OC 9.5.6.2. The SO shall provide at least two or more dedicated Public Switched Telephone Network (PSTN) circuits/ extensions and/or cellular connections at designated Control Centre(s). This facility shall be reserved for operational purposes only, and shall be continuously attended by a person meeting the requirements of OC 9.4.2.3 and answered without undue delay.

OC 9.5.6.3. Users shall provide at least two dedicated Public Switched Telephone Network (PSTN) circuits/extensions and/or cellular connections at the Control Facility.

OC 9.5.6.4. Users shall also provide at least one dedicated facsimile unit, connected to a dedicated Public Switched Telephone Network (PSTN) circuit at the Control Facility.

OC 9.6. **Other Requirements**

OC 9.6.1. **Access and Security**

All SCADA, remote telemetry equipment, computer and communication equipment that interfaces with the SO and the information carried by it must be secure from unauthorized access. Procedures governing security and access shall be agreed by the SO with the Users, but shall allow for adequate access to the equipment and information by the SO or its representatives for the purposes of maintenance, repair, testing and recording of readings.

OC 9.6.2. **Time Standards**

Time will be set by a standard determined by the SO. All the relevant SCADA System, remote telemetry and tele-communication equipment will be synchronized with Global Positioning System (GPS) to maintain time coherence. Pakistan Standard Time (PST) (GMT+5) will be used as the time standard. Any Day Light Saving Time (DST) provision, if any, will be considered while synchronizing time with GPS.

OC 9.6.3. **Cyber Security**

a. The SO, TNOs/DNOs and Users must ensure Cyber Security of all the remote telemetry and communication equipment at their respective ends.

In this regard, firewalls and Intrusion Prevention Systems (IPS) must be used by all the code participants. All remote telemetry and communication facilities (including SCADA) shall not be connected to the utility communication network through insecure connection.

b. Additionally, all Users shall also ensure cyber security of ICT infrastructure, control systems and other Cyber Assets at their ends as per guidelines and/or standards issued by SO from time to time.

OC 9.6.4. **Uninterrupted Power Supplies**

All SCADA, remote telemetry equipment, computers, networking and communication equipment must be provided with redundant Uninterrupted Power Supplies (UPS) at SO, TNOs/DNOS and Users sites, at the cost of respective Code Participant. The UPS arrangement shall have adequate capacity to support all the essential services at SO, TNOs/ DNOs and User's Sites during any emergency condition on National Grid to allow for communication between the SO and Users facility. The power supplies shall have at least 50% spare capacity for future expansion.

OC 9.7. **Communications**

OC 9.7.1. Other than where specifically provided for in other sections of the Grid Code, communication between the SO and Users on matters pertaining to the real time operation of the National Grid shall take place between the SO's and the User's Control Facility.

OC 9.7.2. If the SO or the User Control Centre/Facility is moved to another location, the SO shall notify the Users or the relevant User shall notify the SO (as the case may be) without delay of the new location and any changes to the communication facilities necessitated by such a move.

OC 9.7.3. Unless otherwise specified in the Grid Code, all instructions given by SO and communications between SO and the User's Control Facility shall be given by means of the facilities described in OC.9.6.

OC 9.7.4. Any automatic recording (by whatever means) of communications given by means of telephony, electronic means, facsimile transfer or telex will be accepted by the SO and Users as evidence of those instructions or communications.

OC 9.8. **Communication with Cross-Border SO**

OC 9.8.1. In order to discharge its responsibilities in respect of the safe, secure and reliable operation of the Interconnected Transmission System, the SO will need to carry out communication with the cross border System Operator(s)/ Load Dispatch Centre(s). The communication flow and operating procedures between the SO and Cross-Border SO/LDC shall be governed by the relevant Agreement(s).

OC 9.9. **Data and Notices**

OC 9.9.1. Data and notices to be submitted to the SO or to Users under the Grid Code (other than data and notices which are the subject of a specific requirement of the Grid Code as to the manner of their delivery) shall be in Writing and shall be delivered by hand or sent by pre-paid post, by telex, receipted email or tele facsimile transfer.

OC 9.9.2. Data and notices to be submitted to the SO under the Grid Code shall be addressed to the person, and at the address, notified by the SO to Users for such purpose.

OC 9.9.3. Data and notices to be submitted to Users under the Grid Code shall be addressed to the User's nominated representative at the address notified by Users to the SO for such purpose or, failing such notification to the principal office of the addressee, to such other person or address as Users may notify to the SO from time to time.

OC 9.9.4. All data items, where applicable, will be referenced to nominal Voltage and Frequency unless otherwise stated.

OC 9.9.5. All Operational Data is to be supplied in accordance with the timetables set out in the Grid Code.

OC 9.10. **Data Retention**

OC 9.10.1. Operational Data is all data required to be supplied by either the SO or Users under the Grid Code and any other data expressly provided to be Operational Data under the Grid Code. Operational Data to be supplied by the User must be submitted to the department or address as the SO may from time to time advise.

OC 9.10.2. The SO shall maintain a complete and accurate record of all Operational Data supplied or maintained under the Grid Code. The format for the retention of records shall be as the SO may reasonably determine (provided such format shall not prejudice its accessibility and comprehension by the User under OC.9.10.4). All Operational Data shall be so maintained for a period of not less than ten (10) years commencing from the date the Operational Data was first supplied (or first created, if earlier).

OC 9.10.3. The SO and the User shall keep all Operational Data communicated between them as confidential.

OC 9.10.4. The SO shall afford Users access to its records (and copies thereof) of Operational Data and/or data required to be maintained under OC.9.10.2 on reasonable notice.

OC 10. **OPERATIONAL TESTING**

OC 10.1. **Introduction**

OC 10.1.1. OC.10 deals with the responsibilities and procedures for arranging and carrying out Operational Tests which may have an effect on the Transmission System or the system of any User.

OC 10.1.2. By their nature, Operational Tests may impinge on either or both of:

(a) the SO's responsibilities in respect of the Transmission System, including Dispatch of Generation, Interconnectors and Demand Side Unit MW Availability; and

(b) the operations of Users and the quality and continuity of supply of electricity to them.

OC 10.1.3. To minimize disruption to the operation of the Transmission System and the Systems of other Users, it is necessary that tests which affect the operation of the Transmission System or Users' Systems as under OC.10.1.2 are subject to central co-ordination and control.

OC 10.1.4. To achieve the primary objective as outlined in OC.10.2.1, OC.10 sets out the procedures for conducting and reporting Operational Tests on the National Grid.

OC 10.2. **Objective**

OC 10.2.1. The primary objective of OC.10 is to establish a structured procedure for central co-ordination and control of an Operational Test required by the SO or a User, where such test will or may:

(a) affect the secure operation of the Transmission System; or

(b) have a significant effect on the operation of the Transmission System or a User System; or

(c) affect the economic operation of the Transmission System or User System; or

(d) affect the quality or continuity of supply of electricity to Users.

OC 10.2.2. By way of example, tests that will be typically covered by OC.10 are listed in OC.10.4 and OC.10.5. This list is not exhaustive and other tests may also fall within the scope of Operational Tests and shall be covered under this OC.10.

OC 10.2.3. OC.10 does not cover tests which the SO may conduct to assess compliance of Users with their design, operating and performance requirements as specified in the Grid Code and in a User's Connection Agreement, Ancillary Services Agreements and System Support Agreement, or to assess that Generators or Interconnectors are in compliance with their Registered Data as notified by Declarations, where appropriate, or to determine that Generators or Interconnectors are in compliance with Dispatch Instructions, or Commissioning or re-Commissioning Tests. These issues are covered under OC11 (Monitoring, Testing and Investigation).

OC 10.2.4. A system test proposed by a User that shall have no effect on the Transmission System or the System of any other User is not subject to this sub-code. A system test proposed by the System Operator shall always to subject to this sub-code.

OC 10.3. **Scope**

OC.10 applies to the SO and to all Users, which term in this OC.10 means:

(a) Generators which includes all Generators with units with Registered Capacity greater than 10 MW and Generator Aggregators;

(b) Energy Storage Units (ESUs);

(c) Interconnectors;

(d) DISCOs/BPCs;

(e) Transmission Network Operators; and

(f) Distribution Network Operators.

OC 10.4. **Tests Required by the SO**

OC 10.4.1. The SO may need to carry out Operational Tests on the Transmission System in order to train staff, and to acquire information in respect of National Grid behavior under abnormal operating conditions. The SO will endeavor to limit the frequency of Operational Tests only to those that are absolutely necessary and shall always follow Prudent Utility Practices when conducting these Tests.

OC 10.4.2. Operational Tests required by the SO from time to time shall include, but not limited, to the following:

(a) Tests involving the controlled application of Frequency and/or Voltage variations aimed at gathering information on National Grid behavior;

(b) National Grid restoration Tests;

(c) Testing of standing procedures for System Emergency Conditions and Alert conditions; and

(d) Testing or monitoring of Power Quality under various National Grid conditions and configurations.

OC 10.4.3. Where the SO intends to carry out an Operational Test pursuant to OC.10.4 and, in the SO's reasonable opinion, such Test will or may have an Operational Effect on a User’s System, the SO shall, in accordance with OC.8 provide such notice to the User of the scheduled time and effect of the Operational Test as is reasonable in all the circumstances and shall keep the User informed as to any changes to the scheduled time and nature of the Operational Test.

OC 10.4.4. A User, having been informed about an Operational Test under OC.10.4.3 may, acting reasonably, contact the SO to request additional time to consider the impact of the proposed Test on the User system. The SO shall co-operate with the User to assess the risks. The test shall not proceed until all the Users with potential adverse impacts are satisfied except where, in the SO’s view, a User is acting unreasonably.

OC 10.4.5. Operational Tests shall be witnessed by the SO and any other User that will or may be affected by the Test.

OC 10.4.6. The provisions of OC.10.6, OC.10.7, OC 10.8, OC.10.10.4 and OC.10.11 shall not apply to Operational Tests required by the SO under this OC.10.4.

OC 10.5. **Tests Required by the Users**

OC 10.5.1. Operation of Users' Plant and Equipment may also require Operational Testing in order to maintain and develop operational procedures, test and measure performance, comply with statutory or other regulatory obligations and to train their staff.

OC 10.5.2. In accordance with Good Industry Practice, each User shall endeavor to limit the frequency of such Operational Tests and to limit the effects of such Tests on the Transmission System or the systems of other Users.

OC 10.6. **Procedure for Requesting Operational Tests**

OC 10.6.1. Users shall submit their proposals to the SO for an Operational Test in a timely fashion in accordance with OC.8 and OC.9 or alternative procedures agreed with the SO.

OC 10.6.2. As part of the proposal, the User, when requesting an Operational Test, shall supply sufficient detail to the SO to allow it to adequately asses any operational consequences of the proposed Test. This shall include the following information:

(a) the reason for the proposed Test indicating whether the Operational Test is a Test required by statute, required for compliance with licensee conditions, regulations, or safety codes, which may require that execution of the Operational Test be expedited and given priority over other Operational Tests.

(b) The preferred time or times for the test;

(c) The milestones for individual stages of the Operational Test (if any) which can be completed separately, and/or do not require to be repeated if the Operational Test is interrupted by the SO after completion of each stage;

(d) Whether there may be an adverse material impact on the User if the Operational Test is cancelled at short notice or delayed (reasonable detail being given by the User to the SO of the impact).

(e) The Dispatch or Dispatches required by the User for completion of the test, if any, including the duration of Dispatch shall be supplied to the SO as part of the proposal.

(f) Where the User may not know the entire Dispatches required for completion of the test until part of the test is completed then the User, when proposing the test, shall:

(i) divide the test into sections as appropriate;

(ii) indicate and discuss with the SO which sections of the test can be completed in stages and which cannot; and

(iii) indicate possible variations of the test for the sections that can be completed in stages.

Additionally, the factors that influence the completion of the stages should be outlined to the SO, namely, if the procedure to be followed for a certain stage depends on the outcome of a previous stage.

OC 10.6.3. A request by the User for an Operational Test requiring a Generating Unit, Interconnector or Demand Side Unit to be Dispatched to a particular MW Output or operating condition shall not be considered a Re-declaration of Availability, Ancillary Service capability or Operating Characteristics.

OC 10.6.4. The SO may also initiate an Operational Test if it determines that this test is necessary to ensure the safety, stability, security, and reliability of the Transmission System.

OC 10.7. **Evaluation of Proposed Operational Tests**

OC 10.7.1. The SO shall, on receipt of an Operational Test request from the User, assess the impact of the proposed test on the operation of the Transmission System. The SO may request additional information from the User required to evaluate the impact or impacts of the test.

OC 10.7.2. The Test Proponent shall provide sufficient time for the SO to evaluate/plan the proposed test. The SO shall determine the time required for each type of the test. However, the associated costs shall be borne by the User requesting the test(s).

OC 10.7.3. The SO will evaluate the impact (in terms of continuity and quality of supply only) of the Operational Test with significant potential effects on other Users. The SO shall determine and notify other Users, other than the Test Proponent, that may be affected by the proposed Operational Test.

OC 10.8. **Approval for Operational Testing**

OC 10.8.1. Within one (1) month after the acceptance of a Test Request, the SO shall notify the Test Proponent, and the Affected Users of the proposed test. The notice shall contain the following:

(a) the purpose and nature of the proposed test, the extent and condition of the Equipment involved, the identity of the Test Proponent, and the Affected Users;

(b) an invitation to nominate representative(s) for the Test Group to be established to coordinate the proposed test; and

(c) if the test involves work or testing on (E)HV Equipment, the responsible person(s) for Safety assurance shall be informed by the Users and the Safety procedures specified in OC.13 shall be followed.

OC 10.8.2. The Test Proponent and the Affected Users shall nominate their representative(s) to the Test Group within one (1) week after receiving the notice from the SO.

OC 10.8.3. If an Affected User fails to nominate its representative within the period stipulated in (OC 10.8.2), the SO will issue a reminder to that User asking the time. If the User still does not nominate its representative, The SO may decide to proceed with the proposed test and may appoint another "independent third party expert" to the Test Group to represent the interests of that User.

OC 10.8.4. The SO shall establish a Test Group and appoint a Test Coordinator, who shall act as lead of the Test Group. The Test Coordinator may come from the SO or the Test Proponent.

OC 10.8.5. The members of the Test Group shall meet within two (2) weeks after the Test Group is established. The Test Coordinator shall convene the Test Group as often as necessary.

OC 10.8.6. The agenda for the meeting of the Test Group shall include the following: (i) the details of the purpose and nature of the proposed Test and other matters included in the Test Request; (ii) evaluation of the Test Procedure, including sequence of operations and dispatch, as submitted by the Test Proponent and making necessary modifications to come up with the final Test Procedure; (iii) the possibility of scheduling the proposed test simultaneously with any other test(s) and with Equipment maintenance which may arise pursuant to the Maintenance Program requirements of the SO or the Users, to minimize their adverse impacts on the Transmission System or other Users.; and (iv) the economic, operational, and risk implications of the proposed test on the Transmission System or the systems of other Users, and the Scheduling and Dispatch of the Generating Unit/Station.

OC 10.8.6.1. The Test Proponent and the Affected Users (including those which are not represented in the Test Group) shall provide the Test Group, upon request, with such details as the Test Group reasonably requires for carrying out the proposed Operational Test.

OC 10.8.7. Within two (2) months after the first meeting and at least one (1) month prior to the date of the proposed Operational Test, the Test Group shall submit to the SO, the Test Proponent, and the Affected Users a proposed Test Program which shall contain the following:

(a) a plan for carrying out the test;

(b) the procedure to be followed for the test, including the manner in which the test is to be monitored;

(c) list of responsible persons, including those responsible for coordinating on Safety, when necessary, and who will be involved in carrying out the test;

(d) allocation of costs; and

(e) such other matters as the Test Group may deem appropriate and necessary and are approved by the management of the Affected Users.

OC 10.8.8. The Test Group shall use reasonable endeavors to prioritize Operational Tests where the Test Proponent has notified the SO that Operational Tests are required in accordance with licensee conditions, statutory regulations or safety codes or a delay in the execution of the tests may have an adverse material impact on a User.

OC 10.8.9. If the proposed Test Program is acceptable to the SO, the Test Proponent and the Affected Users, the final Test Program shall be prepared and notified to the SO, the Test Proponent, and the Affected Users, and the test shall proceed accordingly. Otherwise, the Test Group shall revise the Test Program to make it acceptable.

OC 10.8.10. If the Test Group is unable to develop a Test Program or reach a consensus in implementing the Test Program, the SO shall determine whether it is necessary to proceed with the test to ensure the Security of the Transmission system.

OC 10.8.11. If the Test Proponent or Affected Users are not satisfied with the Test Program, they shall inform the SO of their concerns. The SO shall not cancel the Test Program unless these objections are reasonable. If the Test Proponent or Affected Users are still not satisfied with the Test Program being approved, then they may appeal the decision to the GCRP in accordance with CM.

OC 10.9. **Scheduling and Dispatch of Operational Tests**

OC 10.9.1. Operational Tests will usually, but not necessarily, be scheduled by the SO in accordance with SDC1.

OC 10.9.2. Where an Operational Test is requested by a User, the User shall submit Availability Notice consistent with planned Operational Tests in accordance with SDC1. The User shall also submit all other data as required under the SDC 1.

OC 10.9.3. Dispatch Instructions for Operational Tests shall be issued by the SO in the normal manner for issuing Dispatch Instructions in accordance with SDC2.

OC 10.9.4. The SO shall use reasonable endeavors to ensure that scheduled Operational Tests are conducted in accordance with the agreed Dispatch procedures.

OC 10.9.5. Where the SO foresees a requirement or likely requirement to cancel, postpone or otherwise significantly alter an agreed Dispatch procedure and schedule, then the SO shall inform the Test Group as soon as is reasonably possible. In this case, the provisions of OC.10.9.6 and OC.10.9.7 shall apply.

OC 10.9.6. Where the SO assesses that the impact of an Operational Test on Transmission System security or on the continuity and quality of supply or operation of a User may or is likely to be significantly greater than originally estimated, the SO may contact the Test Group to discuss a revised test procedure or schedule.

OC 10.9.7. The SO may, where it considers necessary, cancel, interrupt or postpone an Operational Test at any time, but shall where possible utilize the procedures outlined under OC.10.9.6 prior to taking such action where the cancellation, interruption or postponement is for other than technical reasons.

OC 10.9.8. If the Test Proponent wishes to cancel/postpone an Operational Test either before commencement of the Test or during the Test, the SO/Test Group must be notified by the Test Proponent, in accordance with OC.8 and OC.9.

OC 10.10. **Test Reporting**

OC 10.10.1. Upon conclusion of the scheduled time for an Operational Test, the Test Proponent shall notify the SO, Test Group and Affected Users as to whether the

Test has been completed, or sections of the Test if divided into sections under OC.10.6.2 (c)have been completed.

OC 10.10.2. At the conclusion of the Operational Test, the Test Proponent shall be responsible for preparing a written report on the Operational Test (the "Final Report") which shall be available within three months of the conclusion of the Operational Test to the SO, the Test Group, Affected Users and the NEPRA.

OC 10.10.3. 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 as they relate to the SO and Affected Users.

OC 10.10.4. The Final Report shall not be submitted to any person who is not a representative of the SO or the Test Group unless the SO and the Test Proponent having reasonably considered the confidentiality issues arising, shall have unanimously approved such submission.

OC 10.10.5. After the submission of the Test Report, the Test Group shall stand dissolved.

OC 11. **MONITORING, TESTING AND INVESTIGATION**

OC 11.1. **Introduction**

OC 11.1.1. To ensure safe, secure and economic operation of the Transmission System and in respect of Dispatch of Generators, Interconnectors, Demand Side Units and ESUs, the SO will need to carry out certain Monitoring, Testing and Investigation in respect of the performance of Users' Plant and Apparatus.

OC 11.1.2. OC 11 details the procedures the System Operator will follow to monitor and assess the fulfillment of the committed performance of any Generator, Interconnector, ESU, Demand Side Unit or TNOs. The System Operator will also monitor and assess the fulfillment of the committed Ancillary Services of Users as and when required.

OC 11.1.3. OC.11 does not apply, however, to Operational Tests, which may be required by the SO or by Users. The procedures by which Operational Tests are notified, approved, executed and reported are covered under Operational Testing OC 10.

OC 11.1.4. Monitoring is required by the SO to periodically verify the Users' compliance with the Grid Code provisions.

OC 11.1.5. Testing is required by the SO to validate and verify performance of the Users in routine and/or if suspected of deterioration.

OC 11.1.6. Where necessary, the System Operator will also conduct Black Start Tests to ensure satisfactory operation of the relevant Generators/Interconnectors in the event of an Emergency.

OC 11.2. **Objective**

OC 11.2.1. The primary objectives of OC.11 are to establish procedures for verifying that Users are operating within their design, operating and connection requirements, as specified in the Grid Code, Connection Agreements, Ancillary Services Agreements or any other Agreements.

OC 11.2.2. In order to achieve the primary objective, set out in OC.11.2.1, OC.11 establishes procedures for Monitoring, Testing and Investigation. In particular, to facilitate adequate assessment of each but not limited to the following:

(a) Whether Centrally Dispatched Generating Units (CDGUs), Interconnectors and Demand Side Units comply with Dispatch Instructions;

(b) Whether Generators, Interconnectors, Demand Side Units, DISCOS, TNOs and Generator Aggregators are in compliance with their Declarations of Availability, Ancillary Services capabilities, Technical Parameters and any other data required to be registered by those Generators, Interconnectors, ESUs, Demand Side Units, DISCOs, TNOs and Generator Aggregators under the Grid Code;

(c) Whether the Power Quality at User's Connection Points conforms with CC.8;

(d) Whether Users are in compliance with protection requirements and protection settings under the Grid Code, Users' Connection Agreements, Ancillary Service Agreements;

(e) Whether the Generators designed to operate on multiple fuels have the ability to generate on Primary Fuel and Secondary Fuel and have the ability to carry out an on-line fuel changeover; and

(f) Whether Generators referred in (e) above have the required Fuel stock levels at the Generator Site and Off-Site Storage Location.

OC 11.3. **Scope**

OC 11.3.1. OC 11 applies to the System Operator and to Users:

(a) Generators, which, for the purposes of OC.11, include all Generators with Generating Unit(s) subject to Central Dispatch or with Generating Unit(s) that have a total Registered Capacity greater than 10 MW on a single Site;

(b) Interconnectors;

(c) Energy Storage Units (ESUs)

(d) DISCOs/Suppliers/BPCs;

(e) Transmission Network Operators;

(f) Distribution Network Operators.

OC 11.4. **Monitoring**

OC 11.4.1. Monitoring will be normally continuous or continuous for periods of time, and shall be carried out by the SO by monitoring, data recording and analysis or by such other methods as the SO considers appropriate in the prevailing circumstances. It may not require advance notification from the SO to Users in every case.

OC 11.4.2. Monitoring may be carried out by the SO at any time and may result, without the application of further Testing, in the evaluation of User's non-compliance. Where the User disputes a finding of non-compliance, the SO shall provide the User, on request, any data collected during Monitoring over the period of alleged non-compliance and such other documentation as is reasonably necessary to show evidence of non-compliance.

OC 11.4.3. Procedures and systems used for assessment of compliance will be either generic procedures (which will be provided by the SO) or otherwise agreed between the SO and the User, such agreement not to be unreasonably withheld.

OC 11.4.4. Performance parameters that the SO Monitor shall include, but are not limited to, the following:

(a) Compliance with Dispatch Instructions;

(b) Compliance with Declarations including, without limitation, in respect of:

(i) Primary, Secondary and Tertiary Operating Reserve provided by relevant Users, following a Low Frequency Event on the Transmission System;

(ii) Frequency Regulation provided by relevant Users (to confirm that it is consistent with the Declared Governor Droop)

(c) Compliance of the User with Power Quality requirements and standards [such as IEEE Std. 519-1992: IEEE Recommended practices and requirements for Harmonic control in Electric power systems. IEEE standard 141-1993, IEEE Recommended practice for electric power distribution for industrial plants. IEEE standard 1159-1995, IEEE recommended practice for Monitoring electrical power quality; IEC 61000: Electromagnetic Compatibility (EMC).

(d) Defense Plan implementation (ALFDD/ ALVDD/ SPS etc.) and healthiness, compliance for protection system healthiness, compliance for substation physical healthiness, PSS tuning, black start facility during restoration;

(e) Provision of static and dynamic Reactive Power; and

(f) Monitoring of Primary Fuel and Secondary Fuel capability, on-line changeover capability and fuel storage levels.

OC 11.4.5. If there is any persistent non-compliance by a User, the System Operator shall notify the User in writing requiring an explanation of the non-compliance and the User shall have to comply with their obligations.

OC 11.4.6. The SO and the User shall discuss the proposed action to make its facilities compliant with the committed performance and endeavor to reach an agreement on the proposed action. If agreement cannot be reached within ten (10) working days of notification of the failure by the System Operator to the User, the SO or the User shall be entitled to require a test as detailed in OC 11.5.

OC 11.5. **Testing**

OC 11.5.1. The SO may, from time to time, carry out Tests to achieve the objectives described in OC 11.2. The SO may:

(a) from time to time and for the purposes of Testing, issue a Dispatch Instruction under SDC2 or by such alternative procedure as is required or permitted by this OC11;

(b) induce controlled Power System Frequency or Voltage conditions or variations for the purpose of determining that a User Facility's response is in accordance with its Declared Availability, committed Ancillary Service capabilities and Operating Characteristics; and

(c) verify by Testing in accordance with the Test procedures specified in OC.11.5.7, that the User is in compliance with its Declared values/Technical Parameters (such as Annual Capacity Test, Heat Rate Test etc.)

(d) instruct Start-Up on Secondary Fuel, or on-line changeover at Primary Fuel switchover output from Primary Fuel to Secondary Fuel or from Secondary Fuel to Primary Fuel at Secondary Fuel switchover output;

(e) having given the Generator two working days' notice, send a representative to the Generator's Site to verify the Fuel stock levels both at the onsite Fuel storage location and if required at the Off-Site Storage Location; or

(f) any other Test(s) SO may consider necessary for fulfillment of its licensed obligations and Grid Code requirements

(g) All costs associated with the Test shall be borne by the respective User(s) as per Commercial Code.

OC 11.5.2. Testing may involve attendance by the SO or its representative at User Sites in order to carry out Tests in accordance with the testing procedures set out in OC 11.5.7.

OC 11.5.3. A Test may require the User to carry out specific actions in response to a Dispatch Instruction.

OC 11.5.4. The results of a Test may be derived from the Monitoring of performance during the Test.

OC 11.5.5. The results of the performance of the User's facility under test shall be recorded at the SO facility using SCADA or any other means provided to the SO by the User.

OC 11.5.6. If the results are recorded on Site, representatives appointed and authorized by the SO shall witness the test.

OC 11.5.7. **Test Procedures**

OC 11.5.7.1. SO shall prepare User-specific and/or test-specific procedures in coordination with all relevant Users.

OC 11.5.7.2. The proposed procedure for a Test will be notified to the User by the SO in advance of the Test. For an existing procedure, three (3) working days' notice shall be given.

OC 11.5.7.3. For a new procedure, the SO will give a prior notice of seven (7) days to the User. On receipt of such a notification, the User, acting in good faith may, by giving the SO five (5) days' notice, can reasonably object to the proposed procedure on the grounds that there will be a material risk to the safety of the User's Plant or personnel, or that the proposed procedure is technically infeasible or inappropriate to the purpose (in accordance with Good Industry Practice), giving full details of its concerns. In the event that the User so objects, the SO may, as it considers necessary, modify the procedure and re-notify the User.

OC 11.5.7.4. The SO shall treat information collected from Users during monitoring and testing as confidential.

OC 11.5.8. **Black Start Testing**

OC 11.5.8.1. The SO may require a User with a Black Start Station to carry out a test (a "Black Start Test") on a CDGU/facility in a Black Start Station either while the Black Start Station remains connected to an external alternating current electrical supply (a "Black Start Unit Test") or while the Black Start Station is disconnected from all external alternating current electrical supplies (a "Black Start Station Test"), in order to demonstrate that a Black Start Station actually has the Black Start Capability.

OC 11.5.8.2. Where the SO requires a User with a Black Start Station to carry out a Black Start Unit Test, the SO shall not require the Black Start Test to be carried out on more than one CDGU/facility at that Black Start Station at the same time, and would not, in the absence of exceptional circumstances, expect any other CDGU/facility at the Black Start Station to be directly affected by the Black Start Unit Test.

OC 11.5.8.3. The SO may require a User with a Black Start Station to carry out a Black Start Unit Test at any time (but not more than once in each Calendar Year in respect of any particular CDGU/facility unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test, and will not require a Black Start Station Test to be carried out more than once in every two Calendar Years in respect of any particular CDGU unless it can justify on reasonable grounds the necessity for further tests or unless the further test is a re-test).

OC 11.5.8.4. When the SO wishes a User with a Black Start Station to carry out a Black Start Test, it shall notify the relevant User at least seven(7) working days prior to the time of the Black Start Test with details of the proposed Test.

OC 11.5.8.5. All Black Start Tests shall be carried out at the time specified by the SO in the notice given under OC 11.5.8.4 and shall be undertaken in the presence of the authorized representative(s)of the SO, who shall be given access to all information relevant to the Black Start Test.

OC 11.5.9. **Procedure for a Black Start (BS) Test**

OC 11.5.9.1. **Black Start Unit Test**

OC 11.5.9.1.1. The relevant Generator shall be synchronized and loaded.

OC 11.5.9.1.2. All auxiliary supply sources in the Black Start Plant where the Generator is located shall be shut down.

OC 11.5.9.1.3. The Generator shall be de-Loaded and de-synchronized, and all alternating current supplies to its auxiliaries shall be disconnected.

OC 11.5.9.1.4. The auxiliary supplies shall be re-started and energize the unit board of the relevant Generator, thereby enabling the Generator to return to synchronous speed.

OC 11.5.9.1.5. The relevant Generator shall be synchronized to the system but not loaded unless instructed to do so by the SO.

OC 11.5.9.2. **Black Start Station Test**

OC 11.5.9.2.1. All Generators at the Black Start Station other than the Generator on which the Black Start Test is to be undertaken, and all auxiliary supplies to the Back Start Station shall be shut down.

OC 11.5.9.2.2. The relevant Generator shall be synchronized and loaded

OC 11.5.9.2.3. The relevant Generator shall be de-Loaded and desynchronized.

OC 11.5.9.2.4. All external alternating current electrical supplies to the generator board of the relevant Generator and to the station board of the relevant Black Start station shall be disconnected.

OC 11.5.9.2.5. The auxiliary supply generator at the Black Start Station shall be started and shall re-energize either directly or via the station board, the unit board of the relevant Generator.

OC 11.5.9.2.6. The relevant Generator shall be synchronized to the System but not loaded unless instructed to do so by the System Operator.

OC 11.5.9.3. **Black Start HVDC systems**

OC 11.5.9.3.1. The HVDC link shall be de-Loaded.

OC 11.5.9.3.2. All external alternating current electrical supplies to HVDC Converter stations shall be disconnected.

OC 11.5.9.3.3. The auxiliary supply generator at the Black Start HVDC Converter station shall be started at the delivering and shall re-energize HVDC control system.

OC 11.5.9.3.4. The HVDC Converter station at the rectifying end is started and energizing the DC transmission line.

OC 11.5.9.3.5. The inverter end of the HVDC link is started and energizing a dead AC bus bar.

OC 11.6. **Investigation**

OC 11.6.1. The SO may, if it suspects noncompliance by the User, carry out investigation to acquire or verify information relevant to User's Plant and Apparatus design, operation, or other contractual requirements under the Grid Code, or the relevant Connection Agreement.

OC 11.6.2. Investigation by the SO usually applies to information not collected on a regular basis by means of monitoring and testing. The SO may, having given reasonable notice, send a representative or sub-contractor to investigate any Equipment or operational procedure on or applicable to the User Site insofar as the condition of that Equipment or operational procedure is relevant to compliance with the Grid Code, Connection Agreement, and/or any other Agreement(s).

OC 11.7. **Consequences of Monitoring, Testing and Investigation**

OC 11.7.1. As a result of Monitoring, Testing and Investigation, the SO may determine that a User is in non-compliance due to any of the following reasons:

(a) Non-compliance with a Dispatch Instruction issued by the SO;

(b) Non-compliance by a Generator and Interconnector with Declared Operating Reserve;

(c) Non-compliance by a User with an Availability Notice;

(d) Non-compliance by a User with Declared Ancillary Services or declared Technical Parameters;

(e) Non-compliance by a User with Connection Code; or

(f) any other case of non-compliance by a User.

OC 11.7.2. When the SO considers that a User is not in compliance, then the SO shall inform the User, identifying the relevant CDGU, Interconnector or Demand Side Unit or any other Equipment and identifying the type and time of non-compliance as determined by the SO. This shall be known as a "Warning for non-compliance". The Warning is to contain appropriate instructions by the SO to make the User compliant with its obligations. The occurrence of the Warning shall be logged by the SO and by the User.

OC 11.7.3. On receipt of a Warning for non-compliance, the User must as soon as possible, and in any case within ten (10) minutes of the receipt of the Warning:

(a) Commence to comply with the instructions included with the Warning; or

(b) Reply to the SO, disputing in good faith the validity of the Warning, detailing the grounds on which the validity is being disputed; or

(c) Reply to the SO, disputing in good faith the validity of the assessment of non-compliance. In this event, User must as soon as be practicable, inform the SO in detail of the grounds on which the assessment of non-compliance is being disputed; or

(d) Reply to the SO, giving a reason for non-compliance, and making a revised Declaration in respect of the Availability, Ancillary Service capabilities or Technical Parameters, as appropriate.

OC 11.7.4. If the User complies in accordance with OC.11.7.3 (a), no further action shall arise.

OC 11.7.5. In the event of the User making a revised Declaration under OC 11.7.3 (d), the SO shall then issue a new Dispatch Instruction (if applicable), consistent with the revised Declaration. The revised Declaration will be backdated to the time of issue of the relevant Dispatch Instruction. Notwithstanding the backdating of the revised Declaration, the User will still be deemed to have been non-compliant under OC 11.7.1.

OC 11.7.6. In the event of OC.11.7.3 (b) or OC.11.7.3 (c) applying, the SO shall consider the substance of the User’s disputation. The SO shall, where the SO considers appropriate, communicate with the User to clarify aspects relating to the issue and receiving of the User’s actions. The SO shall determine the validity of the User’s disputation, and shall inform the User as to its decision. The SO shall record both its decision, and also all pertinent information relating to the event, including the User’s disputation and such information shall be deemed to be Operational Data.

OC 11.7.7. Where the SO is of the view that a disputation given by a User is not valid or not wholly valid or if the User has not replied in accordance with OC.11.7.3, the SO shall inform the User that it is overriding, by means of a Post Event Notice, the User’s Availability Notice or declared Operating Reserve or declared Ancillary Service or declared Technical Parameter or Registered Operating Characteristics (as the case may be). The Post Event Notice shall govern until such times as the User submits a revised Availability/ Declaration Notice.

OC 11.7.8. Where the SO gives a Post Event Notice under OC.11.7.7, the Post Event Notice shall be backdated to the time for which there exists compelling evidence that the User was acting in non-compliance, as determined by the SO. The Post Event Notice shall set the level of Declared Availability, Declared Ancillary Service capability or declared Technical Parameter/ Operating Characteristics, as the case may be, at such level as the Monitoring, Testing or Investigation indicates the User actually achieved.

OC 11.7.9. Notwithstanding the backdating of the Post Event Notice, the User will still be deemed to have been non-compliant under OC 11.7.1.

OC 11.7.10. Following the Post Event Notice, the SO shall make available to the User within reasonable time, the relevant data that the User may reasonably require to substantiate the assessment of non-compliance.

OC 11.7.11. The consequences of non-compliance by a User will be addressed in the Commercial Code, NEPRA Fine Rules and/or other Agreement(s) as appropriate.

OC 11.7.12. In case of OC 11.7.1. (e), the terms of this OC.11.7 shall be without prejudice to the rights of the SO to De-energize the User facility in accordance with the terms of OC.6.

OC 11.7.13. In the event that the Demand Side Unit is deemed by the SO in accordance with the provisions of this OC.11 to be in non-compliance with its Dispatch Instructions, that is the Demand Side Unit failed to comply with three (3) Dispatch Instructions in one calendar month period then the SO shall notify the Demand Side Unit of the continued non-compliance. The Demand Side Unit shall take immediate action to remedy such non-compliance. The terms of this OC.11.7.13 shall be without prejudice to the rights of the SO to inform NEPRA that the Demand Side Unit is in breach of the Grid Code, and the Demand Side Unit may be penalized as per NEPRA Fine Rules.

OC 11.8. **Failure of a Black Start Test**

OC 11.8.1. A Black Start Station shall fail a Black Start Test if the Black Start Test shows that it does not have a Black Start Capability (i.e. if the relevant Generating Unit fails to be Synchronized to the System within two hours of the Auxiliary Gas Turbine(s) or Auxiliary Diesel Engine(s) being required to start).

OC 11.8.2. If a Black Start Station fails to pass a Black Start Test the Generator or Interconnector must provide the SO 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 Generator or Interconnector after due and careful enquiry. This must be provided within five (5) working days of the test. If a dispute arises relating to the failure, the SO and the relevant Generator or Interconnector shall seek to resolve the dispute by discussion. If they fail to reach agreement, the Generator or Interconnector may require the SO to repeat the Black Start Test on forty-eight (48) hours’ notice which shall be carried out following the agreed procedure as the case may be, as if the SO had issued an instruction at the time of notice from the Generator or Interconnector.

OC 11.8.3. If the Black Start Station 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.

OC 11.8.4. If following the procedure in OC.11.8.2 and OC.11.8.3 it is established that the Black Start Station has indeed failed the Black Start Test (or a re-test), within fourteen (14) days, or such longer period as the SO may agree, following such failure, the relevant Generator or Interconnector shall submit to the SO in writing for approval, the date and time by which that Generator or Interconnector shall have brought that Black Start Station to a condition where it has a Black Start Capability and would pass the Black Start Test, and the SO will not unreasonably withhold or delay its approval of the Generator's or Interconnector’s proposed date and time submitted. Should the SO not approve the Generator's or Interconnector’s proposed date and time (or any revised proposal) the Generator or Interconnector shall revise such proposal having regard to any comments the SO may have made and resubmit it for approval.

OC 11.8.5. Once the Generator or Interconnector has indicated to the SO that the Generating Station or Interconnector has a Black Start Capability, the SO shall either accept this information or require the Generator or Interconnector to demonstrate that the relevant Black Start Station has its Black Start Capability restored, by means of a repetition of the Black Start Test referred to in OC 11.5.8.4 following the same procedure as for the initial Black Start Test. The provisions of this OC.11.5.8 will apply to such test.

OC 11.8.6. In the event that the User fails to meet the test criteria specified by SO, the User is required to provide the System Operator with a written explanation of the reasons for failure. If the System Operator and the User are unable to agree, the System Operator may require the User to perform a re-test.

OC 11.8.7. If in the opinion of the System Operator the User again fails the re-Test, every effort should be made to resolve the matter. In the event that a dispute arises between the User and the System Operator, either entity may approach the Review Panel for a determination of the dispute which shall be binding on both entities.

OC 11.9. **Disputation of Assessment of Non-Compliance by a User**

OC 11.9.1. In the event that a User has received notification from the SO of an assessment of non-compliance and/or application of a Post Event Notice under OC.11.7, then the User may reply to the SO disputing in good faith the validity of either the assessment of non-compliance and/or the content of the Post Event Notice, detailing the grounds on which the validity is being disputed. Any disputation should be submitted within twelve (12) hours although additional information in support of the disputation may follow within two (2) working days.

OC 11.9.2. If a User submits a disputation to the SO under OC.11.9.1, then the SO shall consider the substance of the User's disputation. The SO may, where the SO considers appropriate, communicate with the User to clarify aspects of the assessment of non-compliance or the User's disputation.

OC 11.9.3. The SO shall determine the validity of the User's disputation, and shall inform the User within five (5) working days as to its decision. The SO shall alter or revise any assessment of non-compliance and/or Post Event Notices as appropriate.

OC 11.9.4. In the event that there is still disagreement as to the outcome, the dispute shall if requested by either the SO or the User, be referred to GCRP.

OC 11.10. **Failure of Test/Re-Test**

OC 11.10.1. If after the procedure described in OC 11.7, it is accepted that a User has failed the Test or re-Test, the User shall within ten (10) working days submit to the SO a date with a proposal by which the User shall be able to comply with the relevant requirements and its obligations. If the SO does not approve the date and time submitted by the User, the User shall amend such proposal having regard to any comments given by the SO and re-submit it for the SO's approval.

OC 11.10.2. If a User fails the Test, the User shall submit revised limits and other data as may be relevant as per Revised Technical Parameter Notice for the period of time until the User can achieve the Parameters previously registered under CC/PC or demonstrated under SDC.

OC 11.10.3. When the User informs the System Operator that it is able to achieve the Technical Parameters, the System Operator shall either accept this information or require the User to re-Test the User to confirm the stated capability. The System Operator shall give forty-eight (48) hours' notice to the User for a re-Test. The Test shall be conducted in accordance with OC 11.5.7, and the provisions of OC 11.9 and OC.11.10 shall apply to this further test.

OC 12. **SYSTEM RECOVERY**

OC 12.1. **Introduction**

OC 12.1.1. Despite best intentions and efforts, the Transmission System can occasionally come under severe stress and treats as a result of some unforeseen operating conditions or unusual weather events such as major thunderstorm, heavy rains, flooding, dense fog etc.).

OC 12.1.2. Experience shows that electricity supply systems can suffer Partial Shutdown or Total Shutdown under fault and abnormal operating conditions. Collapses can result from a number of root causes but might most typically be due to a high number of Plant failures (Generation and/or transmission) resulting from severe weather conditions and/or mal-operation of protection systems.

OC 12.1.3. It is therefore necessary to provide a proper mechanism in the Grid Code to deal with a Partial Shutdown or Total Shutdown of the Transmission System, and to ensure that the necessary procedures and facilities are in place to support rapid recovery of the Shutdown parts and restore supply to Customers.

OC 12.1.4. A Partial Shutdown or Total Shutdown represents one of the most serious fault situations liable to occur on the Transmission System, having a major effect on both Users of the Transmission System and electricity Customers. High significance of such incidents and urgency in restoring supply to all Customers, makes it imperative that all Users should maintain a high level of awareness and training for National Grid restoration after such Partial or Total Shutdowns.

OC 12.1.5. This OC 12 deals with the procedures for the restoration of power supplies following a Total Shutdown or a Partial Shutdown of the System and the re-synchronization of specific parts of the System that have been Islanded. Where the need for a procedure is identified for the first time for any type of Shutdown or Islanding, and there is no agreement already in place, the System Operator and relevant Users shall coordinate the course of action to be adopted.

OC 12.1.6. The OC 12 requires that effective channels of communications must be established and maintained between senior management of the System Operator, the Transmission Network Operators, Generators, DISCOs, BPCs, Suppliers, Interconnectors, in addition to those channels that are used for day-to-day operations of the Transmission System and User facilities.

OC 12.1.7. In order to mitigate the effects of any national-level emergency, the System Operator and Users shall take quick actions to safeguard the System and facilities connected with it. Such actions may necessitate use of principles and procedures contrary to those laid down in the Grid Code, and as such, the appropriate sections of the Grid Code shall stand suspended till the System is restored to Normal State.

OC 12.2. **Objective**

OC 12.2.1. The objective of OC.12is to ensure that in the event of a Partial Shutdown or Total Shutdown of the Transmission System, normal supply is restored to all Customers as quickly and as safely as practicable in accordance with Prudent Utility Practice. This objective can be subdivided:

(a) To outline the general restoration strategy which will be adopted by the SO in the event of a Partial Shutdown or Total Shutdown of the Transmission System;

(b) To establish the responsibility of the SO to produce and maintain a comprehensive National Grid Restoration Plan, covering both Partial Shutdowns and Total Shutdowns;

(c) To establish the responsibility of Users to co-operate with the SO in the formulation and execution of the National Grid Restoration Plan,

(d) To ensure that the SO and User personnel who will potentially be involved with the implementation of the National Grid Restoration Plan, are adequately trained and fully familiar with the relevant details of this Plan.

OC 12.3. **Scope**

OC.12 applies to the SO and to all Users, which term in this OC.12 means:

(a) Generators;

(b) Interconnectors;

(c) Energy Storage Units;

(d) Transmission Network Operators (TNOs);

(e) Distribution Network Operators (DNOs);

(f) DISCOs/Suppliers/BPCs; and

(g) Transmission Connected Consumers.

OC 12.4. **System Alerts**

OC 12.4.1. In the event of a System Emergency Condition or imminent shortfall of MW capacity, the SO may issue any of several Alerts to the Generators/Interconnectors, key Transmission Stations and Demand Side Units. These Alerts may include a Yellow Alert, Blue Alert or Black Alert or Red Alert, or other Alerts as may be agreed from time to time.

OC 12.4.2. Alerts will normally be transmitted to the User via the Electronic Alert System (except in the case of a failure of the Electronic Alert System when it will be given verbally). The Alert shall cause an alarm in the receiving location, which must be acknowledged by the User in accordance with their Alert procedures.

OC 12.4.3. Standing procedures to be activated in response to an Alert will be developed by the SO, in consultation with Users, and notified to each User as appropriate. These standing procedures will not impose obligations on the User which are not already provided in the Grid Code.

OC 12.4.4. Each User shall be responsible for development of internal procedures, in consultation with the SO, that may be necessary to execute the standing procedures.

OC 12.4.5. **Yellow Alerts**

A Yellow Alert may be issued when a single Event would give rise to a reasonable possibility of failure to meet the National Grid Demand, or of Frequency or Voltage departing significantly from normal, as per OC.5.4.4 and OC.5.5.7, or if multiple Events are probable due to prevailing system or weather conditions.

OC 12.4.6. **Blue Alerts**

A Blue Alert may be issued when, other than as provided for in OC.10, the Frequency or Voltage in the Transmission System has deviated significantly from normal, or when the Contingency Reserve in the System becomes zero, or a Generation deficiency exists, or there is a Critical Loading or imminent overloading of the Transmission lines or Equipment, or User's Demand has been disconnected.

OC 12.4.7. **Black Alert**

The issuing of a Black Alert other than as provided for in OC 12.5.5, by the SO signifies that either a Partial Shutdown or a Total Shutdown of the National Grid has taken place.

OC 12.4.8. **Red Alert**

The issuing of Red Alert signifies that the System is under restoration.

OC 12.5. **Power System Restoration**

OC 12.5.1. A Total Shutdown of the System is a situation when there is no internal generation online and operating; and also there is no power supply available from external connections. The restoration of power supply from such a situation is a Black Start Recovery. A Partial Shutdown is a situation when there is no on-line and operating generation or External Connection to a part of the System that is under Shutdown; and it may be necessary for the System Operator to instruct Black Start Recovery procedures to restore supplies to that part of the System and Synchronize it back to the healthy part of the Transmission System.

OC 12.5.2. The National Grid Restoration Plan will be developed and maintained by the SO in coordination with relevant Users in accordance with Prudent Utility Practice and relevant Agreement(s). It shall clearly define the responsibilities of Users during Total or Partial Shutdown.

OC 12.5.3. The procedure for National Grid Restoration shall be notified by the SO to the User at the time of a Partial Shutdown or Total Shutdown. Each User shall abide by the SO's instructions during the restoration process, subject to safety of personnel and the System's and the User's Plant and Apparatus.

OC 12.5.4. The User shall ensure that their personnel who are expected to be involved in the National Grid Restoration process are fully familiar with, and are also adequately trained and experienced in executing their standing instructions and discharging their obligations so as to be able to implement the procedures and comply with any procedures notified by the SO under OC.12.5.3.

OC 12.5.5. The SO shall in consultation with each User and at least once each year, issue a Black Alert to the Users for the purposes of Testing the Restoration Plan and the preparedness and training of the relevant staff. The content of the drills shall be notified in advance to the Users, and a date and time for execution of the drills shall be agreed and notified. The User must, acting in accordance with Good Industry Practice, co-operate with the SO in successfully carrying out of any such drills.

OC 12.5.6. Following a Total Shutdown of the System, designated power plants that have the ability to Start Up without any External Connection to the System shall be instructed to commence Black Start Recovery procedures. These procedures, which are to be agreed in advance between SO and participating Users, may include the restoration of blocks of local loads that can be restored in coordination with the local Distribution Company. Local procedures may include the restoration of power supplies via Embedded Generators. The System Operator shall be responsible for the re-energization of the Transmission System, and the re-synchronization of the various islanded blocks.

OC 12.5.7. Where the system configuration prevents a Generator from restoring blocks of Load Demand using Black Start, adjacent DISCOs shall reconfigure their system(s) to provide supply to discrete blocks of local load, which shall then be restored on the instruction of the System Operator in liaison with Generators, using islanded parts of the Transmission System.

OC 12.5.8. The complexities and uncertainties relating to the restoration of power supplies following a Total Shutdown or Partial Shutdown of the System dictate that any internal procedure and any local procedure agreed between the System Operator and Users allows for a flexible approach to be adopted in the light of actual circumstance rather than a rigid and inflexible procedure involving prescribed actions.

OC 12.5.9. During the restoration of Load, the System Operator may issue instructions that conflict with a local procedure for the restoration of power supplies. In such an event the System Operator's instructions shall override any previously agreed local procedure.

OC 12.5.10. During restoration process of the Transmission System, the normal standards of voltage and frequency under OC.5.4.4 and OC.5.5.7, and Performance Standards Rules, shall not apply.

OC 12.5.11. Procedures for the restoration of power supplies may include the requirement for the Generators to communicate directly with the DISCOs, on the SO's instructions, so that the restoration of blocks of local power supplies can be managed in a controlled manner to ensure the Generator's stability and safety.

OC 12.5.12. Frequency sensitive automatic load disconnection schemes may be taken out of service during the restoration of load to prevent unwanted disconnection of load.

OC 12.5.13. Generators/ Interconnectors shall not be permitted to reconnect to the Transmission System or install automatic reconnection systems unless specified otherwise by the SO.

OC 12.5.14. The System Operator shall instruct the interconnection of islanded networks to form progressively larger and resilient sub-systems until the complete System has been reconnected properly. This shall be facilitated by using appropriate synchronization facilities (e.g. digital synchro-check relays etc.). Users are responsible to maintain such facilities at all strategic points as identified by the SO, or in accordance with CC.6.2.5.

OC 12.5.15. During the restoration of supplies, the System Operator shall agree the reconnection of the System to any Interconnector as per the relevant Agreement(s).

OC 12.5.16. In case of Total Shutdown, Solar PV Power Plants shall be required to be disconnected from the System. The PV inverter shall have anti-islanding protection built in and shall inject small pulses that are slightly out of phase with the AC electrical system in order to cancel any stray resonances that may be present when the System shuts down.

OC 12.6. **Islanded Network**

OC 12.6.1. If a part of the System gets disconnected from the complete System (islanded), but there has been no resultant Total Shutdown or Partial Shutdown of the System, the System Operator shall instruct the regulation of Generation and/or Demand in the group to enable it to be re-synchronized it back to the complete System

OC 12.6.2. In order to achieve requisite conditions to permit the re-synchronization of the islanded network, the System Operator may adopt one of the following approaches:

(a) The System Operator and the Users in the islanded network may exchange information to enable the System Operator to issue emergency instructions until the islanded network has been successfully re-synchronized. Transfer of Load Demand between interconnection and un-synchronized parts of the System will be at the discretion of the SO.

(b) The System Operator shall issue an emergency instruction to the Operator (s) of power plants in the islanded network to float local Load to maintain Target System Frequency until the islanded network has been re-synchronized. During this period, the Distribution Company is required to inform the System Operator of any anticipated changes in load.

(c) If the supply to a part of the System gets de-synchronized, then that particular part may be shut down and power supplies restored for the Synchronized part of the System, and the remaining system shall maintain power supplies in balance with the relevant demand.

OC 13. **WORK SAFETY**

OC 13.1. **Introduction**

OC 13.1.1. Notwithstanding the standard safety procedure for employee working within Service Territory of Code Participants, OC.13 focuses on the coordination on Safety matters when repair or maintenance work is to be performed at or near the Transmission System (66kV and above).

OC 13.1.2. At times, the TNOs and the Users may need to work on, or in close proximity to the Transmission System. It is imperative that the TNOs and Users operate strictly in accordance with approved Safety Rules and procedures to ensure the Safety of life, network, and Equipment in such situations.

OC 13.1.3. It will also be necessary to facilitate work by third parties in close proximity to Transmission System and Apparatus.

OC 13.1.4. In the event of a conflict between OC.13 and any other section of the Grid Code, the OC.13 shall take precedence.

OC 13.1.5. Not Used

OC 13.1.6. To ensure safe conditions for each and every foreseeable situation during system operation, it is essential that the Transmission Network Operator and the Users operate in accordance with safety rules and procedures as laid down in the NEPRA approved Safety Codes, and other applicable documents. The Transmission Network Operators and Code Participants shall have their own comprehensive Power Safety Procedures in place and available at all times, which shall also cover work on live Transmission System Plant and Apparatus.

OC 13.1.7. OC-13 does not impose a particular set of Safety Rules on the Transmission Network Operator or Users. It also does not replace the safety rules of any Users already in place.

OC 13.2. **Objective**

OC 13.2.1. The objective of OC13 is to ensure that the Users and their respective sub-contractors operate in accordance with approved safety rules, which ensure the safety of personnel working on or in close proximity to Transmission System, Plant and Apparatus, or personnel who may have to work at or use the equipment at the interface between the Transmission System and the User's System.

OC 13.2.2. This will normally involve making electrical equipment dead and suitably isolating/ disconnecting (from all sources of Energy) and Earthing of that equipment such that it cannot be made live.

OC 13.3. **Scope**

OC13 applies to the SO and to the following Users:

(a) Generators;

(b) Interconnectors;

(c) DISCOs/BPCs;

(d) Transmission Network Operators;

(e) Distribution Network Operators;

(f) Transmission Connected Consumers; and

(g) Third parties contracted by any User.

OC 13.4. **Safety Procedures**

OC 13.4.1. The Safety of personnel working on or in close proximity to Transmission System Plant and Apparatus shall be governed by the NEPRA approved Safety Codes, safety procedure of Users, and other applicable documents.

OC 13.4.2. In the event of any conflict with this OC.13, the provisions of the NEPRA approved Safety Codes, safety procedure of Users, and other applicable documents shall take precedence.

OC 13.4.3. Not Used

OC 13.4.4. Where clarification is required regarding the correct interpretation of any provision within the Users Safety procedure, the User shall issue the interpretation following consultation with the relevant parties.

OC 13.4.5. In this document, only the following terms have the following meanings:

(a) HV Apparatus means High Voltage electrical circuits forming part of a system, on which “Safety from the System” is required or on which safety precautions are required to allow work to be carried out on the System.

OC 13.4.6. The words mentioned above are defined as follows:

(a) "Safety from the System" means that condition which safeguards the persons, when work is being carried-out at or near a System, from the dangers which are inherent to the system.”

(b) "System" means any User System and/or the Transmission System, as the case may be.

(c) "Safety Precautions" means isolation and/or Earthing.

(d) Isolation means the disconnection of apparatus from the remainder of the System in which that apparatus has been connected. The integrity of the Isolation being achieved and maintained by the use of an approved isolation device, on which all of the procedures to maintain Safety from the System have been carried out. The means of Isolation shall be maintained in accordance with the rules of the owner of the Isolation Apparatus.

(e) Earthing means the application of a connection between the isolated system and the general mass of earth, by an approved means that is adequate for the purpose, and is required to be in place in a secure condition in accordance with the rules of the owner of the Isolation.

OC 13.5. **Procedure for Safety at the Interface**

OC 13.5.1. There shall be a Designated Safety Coordinator for each User Site. Operating Instructions for each User Site shall, following consultation with the relevant User, be issued by the SO to the User and will include:

(a) Detailed switching sequences for voluntary, fault and emergency switching;

(b) Control and operational procedures;

(c) Not Used

(d) Identity of the authorized operator of the SO and the User(s)

(e) Other matters agreed between the SO and User.

OC 13.5.2. Demarcation of responsibility for safety of persons carrying out work or testing at the User Site and on circuits which cross the User's Site at any point, shall be in accordance with Connection Code or relevant Connection Agreement.

OC 13.5.3. The SO and each User shall co-operate in developing procedures and agreement on any matter that may be relevant for ensuring overall Site Safety and, in particular, the overall safety of equipment at the interface between the Transmission System and the User System.

OC 13.5.4. In the event of a modification or a change in operational practices, which may have an Operational Effect on a User, the User shall inform the SO without any delay.

OC 13.5.5. Adequate means of Isolation / disconnection (from all sources of Energy) and Earthing shall be provided at the work site to allow work to be carried out safely at, or either side of this point, by each User.

OC 13.5.6. Not Used

OC 13.5.7. On completion of work, the Designated Safety Coordinators at each relevant Site shall agree to the cancellation of the Safety documentation and shall ensure all requests and subsequent confirmations have been recorded in their log books. These Logs shall be retained for at least five (5) years.

OC 13.5.8. It is the responsibility of the Designated Safety Coordinator to ensure that all Safety Precautions are maintained in place until completion of work and the cancellation of all safety documentation.

OC 13.5.9. Users shall be aware of clearance limits and shall perform work only within their approved clearance limits. Any work at the boundary of the Connection Point shall not be performed without the supervision of a TNO representative.

(A)INTER-SYSTEM SAFETY RECORD OF INTER-SAFETY PRECAUTIONS (RISSP - R)

(For Requesting Safety Coordinator's Record)

RISSP No.____________

Name and location of the Control Centre:____

Name of Control Centre Operator:____

Name and Location of Grid Station/Work Station: __________

PART 1

1.1 (a)Identification of HV Apparatus where isolation and safety from the system is to be achieved.

____

____

(b) Details of work to be done:____

(c) Any other instructions or safety measures to be taken:___________________________

____

1.2 Identification and Safety Precautions Established

(Whether on the implementing safety coordinator's system or any other Users system connected to implementing safety coordinator system) Tick mark √ in the relevant box.

Identification of HV Apparatus	Location	Isolation	Earthing	Confirm Notices Displayed	Locking Arrangements Provided
(i)	_________	☐	☐	☐	☐
(ii)	_________	☐	☐	☐	☐
(iii)	_________	☐	☐	☐	☐

1.3 Confirmation and Issues

Mr.______________________________ implementing Safety Coordinator at location ________________________________ has confirmed that the safety precautions identified in Para 1.2 have been established and will not be removed until this RISSP is cancelled

Signature: _____________________

Dated: ____________________ Name: ________________________

Time:______________________ (Requesting Safety Coordinator)

Date and Time of Commencement of Work ____

Date and Time of Completion of the Work ____

____

Name & Signature of

In charge of work

(Authorized Person)

PART 2

CANCELLATION

I have confirmed to Mr. ________ implementing Safety Coordinator at location ___________ that all men working on the HV apparatus as identified in Para 1.2 have been withdrawn, and the safety precautions set out in Para 1.2 are no longer required and hence the RISSP is cancelled.

Signature: _________________

Name: ____________________

(Requesting Safety Coordinator)

Dated: ______________________________

Time:________________________________

Date and Time of Re-energizing of Apparatus ____

(B)INTER-SYSTEM SAFETYRECORD OF INTER-SAFETY PREC–UTIONS (RISSP - R)

(For Requesting Safety Coordinator's Record)

RISSP No.___________

Name and location of the Control Centre: ____

Name of Control Centre Operator: ____

Name and Location of Grid Station/Work Station: __________

PART 1

1.1 (a)Identification of HV Apparatus where isolation and safety from the system is to be achieved.

____

____

(b) Details of work to be done: ____

(c) Any other instructions or safety measures to be taken: _________________________

____

1.2 Identification and Safety Precautions Established

(Whether on the implementing safety coordinator's system or any other Users system connected to implementing safety coordinator system) Tick mark √ in the relevant box.

Identification of HV Apparatus	Location	Isolation	Earthing	Confirm Notices Displayed	Locking Arrangements Provided
(i)	_________	□	□	□	□
(ii)	_________	□	□	□	□
(iii)	_________	□	□	□	□

1.3 Confirmation and Issues

I, ________________________________implementing Safety Coordinator at location ___________________ has confirmed that the safety precautions identified in Para 1.2 have been established and will not be removed until this RISSP is cancelled

Signature: __________________

Name: ______________

(Implementing Safety Coordinator)

Dated: _______________________________

Time:________________________________

PART 2

CANCELLATION

Mr. ___________________ requesting Safety Coordinator at location _____________________ has confirmed that the safety precautions set out in Para 1.2 are no longer required and hence the RISSP is cancelled.

Signature: __________________

Name: ____________________

(Implementing Safety Coordinator)

Date: ________________________________

Time:________________________________

Date and Time of Re-energizing of Apparatus ____

SCHEDULING AND DISPATCH CODE

SDC 1. **INDICATIVE OPERATIONS SCHEDULING**

SDC 1.1. **Introduction**

Scheduling and Dispatch Code No.1 (“SDC1”) defines the roles and responsibilities of the System Operator (SO) and other Code Participants in the Scheduling of available resources (Generation, Demand Management, and Interconnector transfers) to serve electricity Demand on the Transmission System at least-cost while ensuring Adequacy, Security and Quality of electricity supply in the National Grid.

SDC 1.2. **Objective**

The objective of SDC1 is to enable the SO to prepare the day ahead "Indicative Operations Schedule" to be used subsequently in the Dispatch process (described in SDC2) during the real time Operation of the National Grid and thereby:

(a) maintain sufficient Scheduled Generation and Demand Management capacity to meet total Demand on the System at all times together with adequate Operating Reserves;

(b) ensure the Integrity, Security and Quality of Supply in National Grid;

(c) minimize system operating cost on principles of Optimal Power Flow;

(d) publish the Indicative Operations Schedule as provided for in this SDC1;

(e) comply with the applicable environmental regulations; and

(f) keep a set of potential Special Actions, to deal with any credible contingency on the Transmission System.

The SO will utilize an appropriate Scheduling program using principles of Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) to fulfil the objectives of this SDC1.

SDC 1.3. **Scope**

SDC1 applies to the SO, and the following Users:

(a) Centrally-Dispatched Generating Units (CDGUs):

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated-solar Generators (CSP), etc.); and

(ii) VRE Generator (run-of-the-river hydro, solar, and wind, etc.)

(b) Energy Storage Units with respect to their supply to or demand on the Transmission System (as may be the case at a specified time, including Battery Energy Storage Systems, Pumped Storage Hydro etc.);

(c) Market Operator (MO);

(d) Transmission Network Operators;

(e) Interconnectors;

(f) Demand Side Units (Distribution Companies, Suppliers and Transmission Connected BPCs); and

(g) Small/Embedded Generators whether represented through some Aggregators or any other arrangement (if required by SO).

SDC 1.3.1. **Responsibilities of the Market Operator (MO)**

The Market Operator (MO) shall be responsible for providing to the SO the Variable Operating Costs and Start-Up Costs of all CDGUs and Interconnectors (if applicable) on [fortnightly] basis for using these in preparation of Indicative Operations Schedule and actual Dispatch based on a SCUC and SCED process.

SDC 1.3.2. **Responsibilities of the System Operator**

SDC 1.3.2.1. The SO shall be responsible for developing a daily Forecast of System Demand (in accordance with OC 2) on the National Grid for the next Schedule Day (initially for each hour of the Schedule Day, but for a finer time resolution, if required by SO in the future).

SDC 1.3.2.2. The SO shall develop or procure a state-of-the-art VRE generation (wind and solar PV) forecasting tool/software/service whose forecast accuracy shall be, at least, as specified in Table OC.2-1. The SO will use this forecast in the Scheduling process and, if necessary, to validate the Availability and expected energy production declared by VRE Generators.

SDC 1.3.2.3. The SO will use these forecasts (SDC 1.3.2.1 and SDC 1.3.2.2) for Scheduling the available resources for the next Schedule Day to match Supply with Demand, with requisite levels of Operating Reserve, Minimum Demand Regulation capability, System Stability requirements, and other System (Ancillary) Services requirements.

SDC 1.4. **Scheduling Process**

SDC 1.4.1. The SO shall develop an Indicative Operations Schedule (IOS) a day-ahead of the following Schedule Day using the process described in this SDC 1.4. This process will be phased and iterative to allow appropriate interactions of the SO with Generators and other Users to match Supply with Demand in the System.

SDC 1.4.2. The Schedule Day shall begin at 00:00 hours on the Schedule Day and shall last for 24 hours until 00:00 hours on the next Schedule Day.

SDC 1.4.3. The Users must submit the requisite data and information to the SO as detailed in this SDC to allow it to prepare the IOS. Since the SO is required to match Generation, Interconnector transfers, and Demand in the System on an instant-by-instant basis, the SO may require some additional information from Users to accomplish this objective. Details of any such additional information requirements will be notified by the SO to the relevant Users, as per the need. If the SO considers this data and information necessary and asks a User for it, the User will provide this data and information without any undue delay.

SDC 1.4.4. Data and information submissions to the SO shall normally be made electronically in accordance with the provisions of OC 9 as well as any agreement between the SO and a particular User. In the event of failure of the Electronic Interface for submitting data and information to the SO, submissions may be made by telephone, fax or any other means of communication acceptable to the SO.

SDC 1.4.5. If any change(s) occur after a User has supplied data and information to the SO pursuant to SDC 1.4.7, the User shall inform the SO, without any delay, of all such changes.

SDC 1.4.6. Based on the data and information supplied by the Users (as described in this SDC 1), the SO will develop Indicative Operation Schedule (IOS) for the following Schedule Day and shall publish this Schedule according to the provisions of Commercial Code and this Grid Code.

SDC 1.4.7. **Availability Notice**

SDC 1.4.7.1. **Requirements**

SDC 1.4.7.1.1. By 1000 hours each day, each User shall notify the SO by means of an Availability Notice (in the forms as set out in Appendix B or such other form as the SO may notify to Users from time to time and publish on its website) its Availability, Available Transfer Capability or Demand Response Capability (as may be the case) for each of its:

(a) CDGUs;

(b) Energy Storage Units (for their generation or demand);

(c) Interconnectors;

(d) Demand Side Units; or

(e) Small/Embedded generators whether represented through an Aggregator or some other arrangement (if required by the SO).

SDC 1.4.7.1.2. The Availability Notice shall state the MW Availability (at levels of MW at the Connection Point) of the relevant User for the next Schedule Day.

SDC 1.4.7.1.3. For Generators, the MW figure stated in the Availability Notice shall be consistent with the resolution of Capacity Certificates in accordance with the Commercial Code.

SDC 1.4.7.2. **Contents**

SDC 1.4.7.2.1. Generating Unit(s) which are affected by ambient conditions shall state in the Availability Notice, their best estimate of the ambient conditions and the resulting Availability for each interval of the Schedule Day to which the Availability Notice relates.

SDC 1.4.7.2.2. When the Availability of a CDGU is zero and Availability Notice is given increasing the Availability of the CDGU with effect from a specified time, such Notice shall (in the case of a steam turbine CDGU) be taken to mean that the CDGU is capable of being synchronized with the Transmission System at that specified time or, (in the case of a gas turbine CDGU), is capable of starting at that specified time. A dispatch instruction issued by the SO to synchronize the ST CDGU to the Transmission System or, as the case may be, start the GT CDGU, at or after the specified time shall be a valid dispatch instruction (regardless of the minimum time to synchronize specified in the relevant Technical Parameters).

SDC 1.4.7.2.3. When a CDGU is synchronized with the Transmission System, and the Generator issues an Availability Notice to increase the level of Availability of the CDGU from a specified time, such notice shall be taken to mean that the CDGU is capable of ramping up to this new increased generation level at that specified time from the previously declared level of Availability (without violating its registered Technical Parameters).

SDC 1.4.7.2.4. When a CDGU is synchronized with the System, and the Generator issues an Availability Notice to decrease the level of Availability of the CDGU from a specified time, such Notice shall be taken to mean that the CDGU is capable of maintaining its output till the specified time as per its previous declared Availability level and will ramp down to the new decreased generation level strictly in accordance with its registered Technical Parameters.

SDC 1.4.7.2.5. Where a Generating Unit is capable of firing on multiple fuels, the Generator shall submit an Availability Notice in respect of each designated fuel for its Generating Unit(s), marked clearly to indicate to which particular designated fuel the Availability Notice relates to.

SDC 1.4.7.2.6. In case of hydro Generators, the Availability Notice shall state the capability of each of its Unit in MW adjusted with respect to the inflow and head of its pond or reservoir (if applicable). The Availability Notice shall also state the parameters related to its reservoir/pond and inflow forecast, in the form as set out in Appendix B (or such other form as the SO may notify from time to time and publish on SO website).

SDC 1.4.7.2.7. In respect of Interconnectors, the Availability Notice shall state the Available Transfer Capability of the Interconnector and shall take account of any further restrictions placed by any relevant Agreement(s).

SDC 1.4.7.2.8. If an Interconnector issues an Availability Notice changing its Available Transfer Capability from any previous level beginning from a specified time, such Notice shall be taken to be effective exactly at that specified time.

SDC 1.4.7.2.9. By 1200 hours each day, each VRE Generator shall provide a forecast of the expected Generation of its plant to the SO on hourly resolution (or a finer resolution if so notified by the SO), for the next Schedule Day. This forecast must have been carried out through a state-of-the-art model with minimum forecast accuracy as indicated in Appendix-E. In addition, not later than four (4) hours before the start of each hour, the VRE Generator must provide a forecast of expected Generation for the said hour, provided, the VRE Generator may revise, only once, the forecast for the said hour no later than three (3) hours prior to the commencement of the hour for which the forecast is revised;

SDC 1.4.7.2.10. If a VRE Generator issues an Availability Notice changing its Availability from any previous level beginning from a specified time, such Notice shall be taken to be effective exactly at that specified time.

SDC 1.4.7.2.11. Notwithstanding that a Generating Unit has been declared unavailable, the Generator shall still submit all data and information that it would have submitted to the SO under this SDC1 had its Generating Unit been declared Available.

SDC 1.4.7.2.12. Generators shall ensure that their Generating Unit(s) are maintained, repaired, operated, and fueled using Prudent Industry Practices and are always compliant with any legal requirements with a view to providing the power delivery, System (Ancillary) Services, Declared Available Capacity, and the Technical Parameters.

SDC 1.4.7.2.13. As a general requirement, all fossil fuel fired Generators shall maintain a fuel stock equivalent to at least 30 days of their operation at full load, unless a different period has been expressly agreed in the relevant Agreement(s).

SDC 1.4.7.2.14. In the case of an Aggregator, the Availability Notice (if required by the SO) shall state the Availability of its aggregated generating units as a whole.

SDC 1.4.7.2.15. In case of a Demand Side Unit, the User shall submit the Demand Side Unit MW Availability and the Demand Unit MW Response Time (or any other parameter as may be specified by the SO) to the SO in the form as set out in Appendix B (or such other form as the SO may notify from time to time and publish on SO website).

SDC 1.4.7.2.16. If a Generator (or Interconnector) submits a Maintenance Outage Notice under (OC4) or SO submits a Post Event Notice under (OC11) in relation to any part of the period covered by the Availability Notice at any time after submission of the Availability Notice, the Generator shall be deemed to have submitted a revised Availability Notice consistent with such Outage Notice or Post Event Notice, as the case may be.

SDC 1.4.7.2.17. If a User has submitted a proposal for conducting a Test on its facility to the SO and the SO has approved the proposal, the User shall submit Test MW Output profile for the unit under Test for the time periods during which their units are under Test. The User shall ensure that the hourly MW profile submitted in respect of a unit under Test aligns with the approved Test start time and Test end time.

SDC 1.4.7.2.18. Users shall employ all reasonable endeavors to ensure that they do not at any time declare by issuing, or allowing to remain effective, an Availability Notice, declare the Availability or Technical Parameters of their facilities at levels or values which are different from those that their relevant facilities could achieve at the relevant time under their relevant contracts, except under unavoidable circumstances and only with prior consent of the SO. The SO can reject declarations to the extent that they do not meet these requirements.

SDC 1.4.7.2.19. Nothing contained in this SDC 1 shall restrict a User from declaring levels or values for their Generating Unit(s) or other resources that are better than their Capacity and Technical Parameters as laid down in their relevant contracts/ agreements/ Capacity Certificates.

SDC 1.4.8. **Additional Requirements**

The following items are required to be submitted by each User by no later than 1000 hours each day. The requirements in SDC 1.4.7 in relation to data apply to this SDC 1.4.8 as if repeated here.

SDC 1.4.8.1. **CCGT Availability**

CCGT Installations shall also submit:

(a) The Availability of each CCGT Unit within each CCGT Complex;

(b) The CCGT Installation Matrix submitted by the Generator in the form as set out in Appendix A (or such other form as the SO may notify to Users from time to time and publish on its website) is used and relied upon by the SO as a 'look up table' to determine the number of CCGT Units within a CCGT Installation which will be synchronized to achieve the MW Output specified in a Dispatch Instruction. When using a CCGT Installation Matrix for Scheduling purposes, the SO will take account of any updated information on the individual Availability of each CCGT Unit contained in an Availability Notice submitted by a Generator pursuant to this SDC1.

(c) In cases where some change in MW Output in response to Dispatch Instructions issued by the SO is inevitable, there may be a transitional variance to the conditions reflected in the CCGT Installation Matrix. Each Generator shall notify the SO as soon as practicable after the event of any such variance.

(d) In achieving a Dispatch Instruction, the range or number of CCGT Units envisaged in moving from one MW Output level to the other shall not be departed from.

SDC 1.4.9. **Generator Works Units**

Once per week, on a day and time specified by the System Operator from time to time but not less than two (2) hours before the occurrence of maintenance Outage, each Generator under central dispatch or Aggregated Generating Unit (if required by the SO) must, in respect of each of its Generating Units, unless the data is supplied in some other agreed and approved form, submit to the System Operator, in writing, details of the Generator Works Units for that Generator since the last submission under this SDC 1.4.9, together with such other information as the System Operator may require in order to calculate the Generator Works Units consumed by each CDGU or Aggregated Generating Unit at that Generator.

SDC 1.4.10. **Revisions**

SDC 1.4.10.1. **Availability Notice**

SDC 1.4.10.1.1. User shall submit to the SO, any revisions to its previously submitted data and information at any time between 1000 hours each day and the expiry of the following Schedule Day.

SDC 1.4.10.1.2. If the revised data and information is received by the SO before 1200 hours on the day prior to the relevant Schedule Day, the SO shall take into account the revised Availability Notice in preparing the Indicative Operations Schedule (IOS).

SDC 1.4.10.1.3. If the revised data and information is received by the SO after 1200 hours but before the end of the following Schedule Day, the SO shall, if it re-Schedules the available resources, take into account the revised Availability Notice in that re-Scheduling.

SDC 1.4.10.1.4. The provisions of SDC 1.4.7 and SDC 1.4.8; shall apply to revision to data submitted under SDC 1.4.10.1.

SDC 1.4.10.2. **Technical Parameters**

SDC 1.4.10.2.1. Any revisions to the registered Technical Parameters (submitted as Registered Data in the PC and CC sub-codes or as per Appendices in SDC) or relevant Agreement (if applicable)) must be well documented and agreed to with the SO including the nature and quantification of the revision, duration of such revision, reason for the revision, and anticipated time when the User will restore the Technical Parameters to their registered values.

SDC 1.4.10.2.2. For such temporary revisions in the Technical Parameters, notification must be made by the User by submitting a Technical Parameters Revision Notice (Appendix C). In accordance with the Generator's obligations under SDC 1.4.7.2.18, such characteristics may only be amended (with the SO's prior consent) in the event of a defect in or failure of a CDGU or any associated Generator equipment. Such amendment shall only take place so long as it takes place in accordance with Prudent Industry Practices, and such repair must reinstate the parameters to the level stated in the Technical Parameters, taking into account the provisions of SDC 1.4.7.2.18, and the Generator must then submit a Technical Parameters Revision Notice re-declaring its reinstated Technical Parameters accordingly. The Generator must specify to the SO of the nature of any such defect or its failure; and of the Generator's best estimate, acting as a reasonable and prudent Generator of the time it shall take to complete the repair and restore the Technical Parameters to their former registered levels.

SDC 1.4.10.3. The SO will re-optimize the Schedules when, in its reasonable judgment, a compelling need arises. As it may be the case that no notice will be given prior to this re-optimization, it is important that Users always keep the SO informed of any changes of Availability and Technical Parameters relating to their facilities immediately as they occur.

SDC 1.4.10.4. For any permanent revision in Technical Parameters in special circumstances, the User shall get the revision approved from NEPRA, based on the impact analysis carried out by SO.

SDC 1.4.11. **Default Availability**

SDC 1.4.11.1. If an Availability Notice is not received, in total or in part, by the SO in accordance with SDC 1.4.7, then the SO will make reasonable efforts to establish contact with the User in question to check whether a complete Availability Notice for a Schedule Day was sent and not received by the SO. For such a case, the Availability Notice for a Schedule Day shall be resubmitted by the relevant User without delay in accordance with the provisions of this section. If no Declaration (or, as the case may be, the data and information necessary to complete the Declaration for a Schedule Day) is received by 1200 hours despite the above reminder, then the SO will use the information provided in the Declaration for the previous Schedule Day to the extent necessary to provide the SO with a complete Declaration. A User which repeatedly fails to submit a reasonably accurate Declaration or does not submit the Declaration in time shall be liable to appropriate sanctions or penalties (or both), as approved by NEPRA.

SDC 1.4.11.2. If any data submitted or deemed to have been submitted on any particular day in any Availability Notice, or any revision is inconsistent with any other data in any other such notice, then the most recently submitted data which, if substituted for the inconsistent data, would make the data in such notices consistent, shall apply for the next following Schedule Day or any other values that the SO may reasonably deem appropriate.

SDC 1.4.12. **Preparation of Indicative Operations Schedule**

SDC 1.4.12.1. Each day by 1700 hours, the SO shall develop, by following the process described in this SDC1, a day ahead IOS on hourly resolution (or a finer time resolution, if considered necessary and notified by the SO in future) for the next Schedule Day using the last valid set of Technical Parameters for the Users as applicable.

SDC 1.4.12.2. In compiling the IOS, the System Operator shall take account of the following factors:

(a) Forecasted Demand and its geographical distribution;

(b) Declared MW capabilities of Generators under SDC 1.4.7 and SDC 1.4.8;

(c) Variable operating cost of each Generating Unit;

(d) The Start-up cost of each CDGU;

(e) In respect of CDGUs, the values of their registered Technical Parameters registered under this Code and other information submitted under SDC 1.4.7 and SDC 1.4.8.

(f) Generating Unit/Station Outages;

(g) Transmission Network Outages;

(h) The need to provide the required Operating Reserve by using the various categories of Reserve as specified in OC5;

(i) The requirements for maintaining Frequency Control;

(j) The inability of any CDGU to meet its full Operating Reserve capability;

(k) Voltage Control and MVAR reactive reserves requirements;

(l) System Stability considerations;

(m) Transmission System losses;

(n) Transmission System operating constraints from time to time;

(o) The availability and cost of power transfers across any Interconnector;

(p) The Energy limits for Hydro Units/Plants;

(q) Fuel constraints relevant to the IOS;

(r) Any existing contract for the purchase of fuel to which a Generator is a party, and the terms of which have been agreed to by the GoP and which impacts the national exchequer;

(s) Monitoring, Testing and/or Investigations to be carried out, or being carried out, under OC11; testing to be carried out, or being carried out, at the request of a User under OC10 and/or commissioning/acceptance testing prior to connection or re-connection or commissioning under the Connection Code;

(t) Operation of Generators over periods of low demand to provide, in the SO's view, a sufficient Minimum Demand Regulation (MDR);

(u) Compliance with applicable environmental standards;

(v) Other matters to enable the SO to meet its License conditions;

(w) Other factors as may be reasonably considered by the SO to be relevant to the IOS.

SDC 1.4.13. **Publication of Indicative Operations Schedules**

SDC 1.4.13.1. The SO shall publish the IOS by 1700 hours each day for the following Schedule Day on its website. However, if during the period in which the Indicative Operations Schedule (IOS) is being prepared, Incidents on the System occur which require a substantial amendment to the data being used in preparing the IOS, the SO may extend the timescale for publication of the IOS to the extent necessary as a result of such Incidents. Such Incidents may include, inter alia, the following:

(a) Changes to System conditions that would impose increased risk to the National Grid and, therefore, would require extra Operating Reserve and flexibility;

(b) Unpredicted Transmission System Outages connecting Generating Units, which place at risk more than the equivalent of one large Generating Unit to secure the System against Faults;

(c) Unpredicted Outage of a Generating Unit/Equipment which imposes increased risk to the National Grid;

(d) Severe weather conditions imposing high risk to the total System Demand;

(e) A Total or Partial Shutdown exists in the System.

SDC 1.4.13.2. The IOS is intended to provide a guide to the expected output requirements from Users and shall not be construed as Dispatch Instructions or orders by itself.

SDC 1.4.13.3. The SO may inform Generating Units before the issue of the IOS for the Schedule Day to which the Instruction relates, if the length of Notice to Synchronize requires the Dispatch Instruction to be given at that time. When the length of the time required for Notice to Synchronize is such that the Generating Unit will not be able to meet the indicative Synchronizing time in the IOS or a subsequent Dispatch Instruction, the Generator must inform the SO without delay.

SDC 1.4.13.4. The SO shall also maintain a log of the SCED model as well as all input parameters used.

SDC 1.4.14. **Content of Indicative Operations Schedules**

The information contained in the IOS will indicate, where appropriate, on an individual Generator, Energy Storage Unit, Demand Side Unit, and/or Interconnector basis, the period and MW output (at the Connection Point/Delivery Point) for which it is Scheduled. In the case of a CDGU which is capable of firing on multiple fuels, it will also indicate the fuel for which it is Scheduled. If no fuel is contained in the IOS, then the most economical fuel available shall be treated as having been indicated.

SDC 1.4.15. **Minimum Demand Regulation (MDR)**

For the reliable, secure, and safe operation of the Transmission System, it is imperative that all Synchronized CDGUs and/or Controllable Solar, Wind & ESUs shall at all times be capable of reducing their MW Output to allow a sufficient regulating margin for adequate Frequency Control. The SO will monitor the MW Output data of the IOS against forecast of System Demand to see whether the level of regulation for any period is sufficient; and may take any shortfall into account in Scheduling and Dispatch process.

SDC 1.4.16. **Notice of Inadequate Operating Margin (NIOM)**

SDC 1.4.16.1. The SO will monitor the output data of the IOS against forecast Demand to see whether the anticipated level of the Operating Reserve for any period is insufficient.

SDC 1.4.16.2. Where this level for any period is anticipated to be insufficient, the SO will indicate through a Notification of Inadequate Operating Margin (NIOM) published on its website (the form of which will be determined by the SO). The NIOM will indicate the nature and extent of the insufficiency and the period for which the insufficiency is anticipated.

SDC 1.4.16.3. The monitoring by the SO will be regular and revised NIOMs may be sent out from time to time. These will reflect any changes in the declared Availability which have been notified to the SO and will reflect any Demand Control which has also been so notified. They will also reflect generally any changes in the forecast Demand and the relevant Operating Reserve.

SDC 1.4.17. **Special Actions**

SDC 1.4.17.1. The IOS may be followed by a list of Special Actions (either pre-Fault or post-Fault) that the SO may request a User to take in respect of a procedure to be followed by a User in order to maintain the integrity of the Transmission System in accordance with the SO operational policies.

SDC 1.4.17.2. For a Generator, such Special Actions may involve a load change or a change of required Notice to Synchronize, in a specific timescale on individual or group of Generating Units basis.

SDC 1.4.17.3. For a DSU, these Special Actions may involve load transfers between the Connection Points or arrangements for Demand Management by manual or automatic means.

SDC 1.4.18. **Data Requirements**

SDC 1.4.18.1. SDC.1 Appendix-A lists, but not limited to, the Technical Parameters for which values are to be supplied by a User in respect of each of its CDGUs, ESUs, Demand Side Units and/or Aggregated Generating Units (if required by the SO) either under the standard planning data under PC, or CC or this SDC 1.

SDC 1.4.18.2. SDC.1 Appendix-B sets out the form for declaration of Availability.

SDC 1.4.18.3. SDC.1 Appendix-C sets out the form for revision in Availability.

SDC 1.4.18.4. SDC.1 Appendix-D sets out the form for revision in Technical Parameters.

SDC 1.4.18.5. SDC.1 Appendix-E provides VRE forecast performance criteria.

TECHNICAL PARAMETERS

Where more than one parameter applies, this is indicated by adding a number at the end of the parameter. E.g. De-loading Rate 1, De-loading Rate 2 etc.

Technical Parameter	CDGU			ESU		Inter-connectors	TNOs	Aggr. Gen.	DSU
	Thermal	Hydro	VRE Gen.	Gen.	Demand				
Block Load Cold	✓	✓	✓	✓				✓	
Block Load Hot	✓							✓	
Block Load Warm	✓							✓	
Charging Capacity				✓	✓				
Cycle Efficiency				✓					
Demand Side Unit MW Availability									✓
Demand Side Unit MW Response Time									✓
Demand Side Unit Notice Time									✓
Deload Break Point	✓	✓	✓	✓					
De-Loading Rate	✓	✓	✓	✓					
Dwell Time Up	✓	✓	✓	✓					
Dwell Time Down	✓	✓	✓	✓					
Dwell Time Up Trigger Point	✓	✓	✓	✓					
Dwell Time Down Trigger Point	✓	✓	✓	✓					
End Point of Start Up Period	✓	✓	✓	✓					
Energy Limit		✓		✓					
Forecast Minimum Output Profile			✓	✓	✓				
Forecast Minimum Generation Profile	✓	✓	✓	✓					
Load Up Break Point Cold	✓	✓	✓	✓					
Load Up Break Point Hot	✓								
Load Up Break Point Warm	✓								

Loading Rate Cold	✓	✓	✓	✓					
Loading Rate Hot	✓								
Loading Rate Warm	✓								
Max Ramp Down Rate	✓	✓	✓	✓		✓			✓
Max Ramp Up Rate	✓	✓	✓	✓		✓			✓
Maximum Down Time	✓	✓	✓	✓		✓		✓	✓
Minimum Down Time	✓	✓	✓	✓		✓		✓	✓
Maximum Generation / Registered Capacity	✓	✓	✓	✓		✓		✓	✓
Maximum On Time	✓	✓	✓	✓		✓		✓	✓
Minimum On Time	✓	✓	✓	✓		✓		✓	✓
Minimum Off Time	✓	✓	✓	✓		✓		✓	✓
Maximum Storage / Charge Capacity				✓	✓				
Minimum Storage / Charge Capacity				✓	✓				
Minimum Generation	✓	✓	✓	✓		✓		✓	
Off to Generating Time				✓	✓				
Off to Spin Pump Time				✓	✓				
(Other relevant technical parameters)	✓	✓	✓	✓	✓	✓	✓	✓	✓
Pumping capacity				✓	✓				
Ramp Down Break Point	✓	✓	✓	✓		✓		✓	✓
Ramp Down Rate	✓	✓	✓	✓		✓		✓	✓
Ramp Up Break Point	✓	✓	✓	✓		✓		✓	✓
Ramp Up Rate	✓	✓	✓	✓		✓		✓	✓
Short Term Maximization Capability	✓	✓	✓	✓		✓		✓	✓
Short Term Maximization Time	✓	✓	✓	✓		✓		✓	✓
Soak Time Cold	✓	✓	✓	✓					
Soak Time Hot	✓								
Soak Time Warm	✓								
Soak Time Trigger Point Cold	✓	✓	✓	✓					

Soak Time Trigger Point Hot	✓								
Soak Time Trigger Point Warm	✓								
Spin Pump to Pumping Energy Time					✓				
Synchronizing Time Cold	✓	✓	✓	✓				✓	
Synchronizing Time Hot	✓							✓	
Synchronizing Time Warm	✓							✓	
Target Charge Level Percentage				✓	✓				
Start of Restricted Range (Forbidden Zone)	✓	✓	✓	✓				✓	
End of Restricted Range (Forbidden Zone)	✓	✓	✓	✓				✓	

A. For each CDGU:

1. in the case of steam turbine CDGUs, synchronising times for the various levels of warmth; (Hot, Warm and Cold)
2. in the case of gas turbine CDGUs, the time from initiation of a start to achieving dispatched load.
3. Basic data:
   a. Governor Droop (%);
   b. Sustained Response Capability.
4. Available reactive power generation both leading and lagging, in MVAR
5. The MW and MVAR capability limits within which the CDGU is able to operate as shown in the relevant Generator Performance Chart;
6. Maximum number of changes to the dispatched fuel per 24-hour period;
7. Maximum quantity of oil in "ready-use tank(s)" and associated pipe work;
8. Maximum number of changes to the designated fuel per 24-hour period;
9. Minimum notice to change the designated fuel;
10. Fuel transition time/ changeover for each CDGU
11. Maximum number of on load cycles per 24-hour period, together with the maximum load increases involved; and
12. Settings of the Unit Load Controller for each CDGU;
13. in the case of gas turbine CDGUs only, the declared peak capacity.
14. In the case of a Gas Turbine Unit, only the data applicable to Gas Turbine Units should be supplied.
15. Ambient temperature curves

B. For the Generator of which the CDGU forms part:

1. Time between synchronising different CDGUs in a Generator taking account of actual off-load periods for the various levels of warmth; and
2. Time between de-synchronising different CDGUs in a Generator.

C. Additional Data items required:

1. Heat Rate Curves, Turbine Efficiency, Power curves for VRE
2. GT to ST Ratios
3. Hydrology Tables (Volume vs Level, Head vs. Capability, etc.)
4. Declared Primary Operating Reserve
5. Declared Secondary Operating Reserve

6. Declared Tertiary Operating Reserve
7. Minimum MW for Primary Operating Reserve
8. Minimum MW for Secondary Operating Reserve
9. Minimum MW for Tertiary Operating Reserve
10. Primary Operating Reserve Decrement Rate
11. Secondary Operating Reserve Decrement Rate
12. Tertiary Operating Reserve Decrement Rate
13. Black Start Capability (Yes/ No)
14. Declared Reactive Power Consumption
15. Declared Reactive Power Production
16. Any other Data and Information required by SO for preparing IOS

D. CCGT Installation Matrix

This matrix is a look up table determining which CCGT Unit will be operating at any given MW Dispatch level. This information will be applied for planning purposes and for scheduling, Dispatch and control purposes as covered in the SDC unless by prior agreement with the SO.

As an example of how the matrix might be filled out, consider a sample unit with a total capacity of 400 MW made up of two 150 MW combustion turbines and one 100 MW steam turbine. In this case, the following ranges might be specified:

0 MW to 50 MW GT1
50 MW to 170 MW GT1 and ST
170 MW to 400 MW GT1 and GT2 and ST

For Example:

Please insert MW ranges and tick the boxes to indicate which units are synchronized to deliver each MW range at the following atmospheric conditions: Temperature 10°C, Pressure 1.01 bar and 70% Humidity.

CCGT Installation	**CCGT Unit Available**					
Output Usable	**1st GT**	**2nd GT**	**3rd GT**	**1st ST**	**2nd ST**	**3rd ST**
	Output Usable					
Unit MW Capacity→	e.g. 150	150	-	100	-	-
Total MW Output Range↓						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						
[ ] MW to [ ] MW						

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: __for example: Thermal Plant___
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: _________________ Dated: _________________

For the Day ______________ (DD/MM/YYYY)

		Available Capacity on Fuel 1 MW			Available Capacity on Fuel 2 … MW		
Hour	**Estd. Temp: C^o**	**Unit 1**	**Unit 2**	**Unit 3 …**	**Unit 1**	**Unit 2**	**Unit 3 …**
00-01							
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature___________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: for example: HVDC
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: _________________ Dated: _________________

For the Day _____________ (DD/MM/YYYY)

Hour	Estd. Temp: C°	Available Capacity, MW	Comments / Notes
00-01			
01-02			
02-03			
03-04			
04-05			
05-06			
06-07			
07-08			
08-09			
09-10			
10-11			
11-12			
12-13			
13-14			
14-15			
15-16			
16-17			
17-18			
18-19			
19-20			
20-21			
21-22			
22-23			
23-24			

Signature____________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: _for example: Hydro Plants_
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: _________________ Dated: _________________

For the Day ______________ (DD/MM/YYYY)

				Declared Available Capacity, MW				
Hour	**Head m**	**Inflow Cusecs or Cumecs**	**Water Indent Cusecs or Cumecs**	**Unit-1**	**Unit-2**	**Unit-3**	**Unit-4**	**Unit-5…**
00-01								
01-02								
02-03								
03-04								
04-05								
05-06								
06-07								
07-08								
08-09								
09-10								
10-11								
11-12								
12-13								
13-14								
14-15								
15-16								
16-17								
17-18								
18-19								
19-20								
20-21								
21-22								
22-23								
23-24								

Signature___________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

AVAILABILITY NOTICE

Daily Declaration of Available Capacity
From: for example: Demand Side Unit
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: _________________ Dated: _________________

For the Day ______________ (DD/MM/YYYY)

Hour	Demand Side Unit, MW Availability	Demand Side Unit, MW Response Time	Comments / Notes
00-01			
01-02			
02-03			
03-04			
04-05			
05-06			
06-07			
07-08			
08-09			
09-10			
10-11			
11-12			
12-13			
13-14			
14-15			
15-16			
16-17			
17-18			
18-19			
19-20			
20-21			
21-22			
22-23			
23-24			

Signature____________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

NOTIFICATION OF REVISED AVAILABILITY NOTICE

Declaration of Revised Available Capacity
From: _for example: Thermal Plants
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: ___________________ Dated: _________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity, MW			Comments/ Notes
Hour	**Estd. Temp: ^oC**	**Declared Available Capacity**	**Estd. Temp: ^oC**	**Revision-1**	**Revision - 2**	**Revision - 3…**	
00-01	-	-					
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature___________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

Declaration of Revised Available Capacity
From: _for example: Hydro Plants
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ___________________ Dated: _________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity, MW			Comments/ Notes
Hour	**Declared Head m**	**Declared Inflow**	**Water Indent**	**Revision-1**	**Revision - 2**	**Revision - 3…**	
00-01	-	-					
01-02							
02-03							
03-04							
04-05							
05-06							
06-07							
07-08							
08-09							
09-10							
10-11							
11-12							
12-13							
13-14							
14-15							
15-16							
16-17							
17-18							
18-19							
19-20							
20-21							
21-22							
22-23							
23-24							

Signature__________________________Name_______________________________________
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

Declaration of Revised Available Capacity – Temperature/ Hydrology Adjustments
From: _for example: HVDC or Thermal Plants_
To: System Operator, Control Centre
Due by: _________ Hrs

Time of Declaration: ____________________ Date: __________________

For the Day _____________ (DD/MM/YYYY)

				Revised Declared Available Capacity, MW	Comments/ Notes
Hour	**Declared Estimated Temp. °C/ Head/ Inflow/ Indent**	**Declared or Revised Declared Available Capacity (MW)**	**Revised Temp. °C/ Head/ Inflow/ Indent**	**Adjusted Declared Available Capacity (MW)**	
00-01	-	-			
01-02					
02-03					
03-04					
04-05					
05-06					
06-07					
07-08					
08-09					
09-10					
10-11					
11-12					
12-13					
13-14					
14-15					
15-16					
16-17					
17-18					
18-19					
19-20					
20-21					
21-22					
22-23					
23-24					

Signature____________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

Declaration of Revised Available Capacity – Temperature/ Hydrology Adjustments
From: _for example: Demand Side Unit
To: System Operator, Control Centre
Due by: ________ Hrs

Time of Declaration: ____________________ Date: _________________ _

For the Day _____________ (DD/MM/YYYY)

Hour	Declared Demand Side Unit, MW Availability	Revised Demand Side Unit, MW Availability	Demand Side Unit MW, Response Time	Comments/ Notes
00-01	-	-		
01-02				
02-03				
03-04				
04-05				
05-06				
06-07				
07-08				
08-09				
09-10				
10-11				
11-12				
12-13				
13-14				
14-15				
15-16				
16-17				
17-18				
18-19				
19-20				
20-21				
21-22				
22-23				
23-24				

Signature___________________________Name____
Position: Commercial Engineer/ Control Engineer (delete as applicable)
Date/Time of issue:

TECHNICAL PARAMETERS REVISION NOTICE

[USERNAME] declares that the under mentioned CDGUs/Demand Sites are presently unable to perform to the characteristics stated in Connection/ Planning Code and that the affected characteristics are mentioned below with revised values that should be used for the purposes of Scheduling and Dispatch.

				Time		
Unit ID	**Technical Parameter Affected**	**Registered Value**	**Revised Value**	**From**	**To**	**Reason**

Examples

1	Governor Droop	4%	4.5%	0000	2400
2	Loading Rate after Hot Start 300+ MW	6.0	2.5	1800	2200

This notice is applicable to schedule day: ____________________

Signature: ____________________

Notes

1. All Availabilities shall be expressed in MW.
2. For each CDGU, an Availability figure must be entered for the first settlement period. Where the CDGU is completely unavailable, a zero shall be entered. Thereafter, an Availability figure shall only be entered where the Availability for the CDGU is changed from the previously expressed value.
3. This Availability Notice shall include all planned Outages agreed with SO and all Unplanned/Forced Outages already notified to SO. It shall not include Unplanned/Forced Outages not yet notified to SO unless the appropriate Outage Notice is attached.

VRE Forecast Errors

For hour-ahead intraday generation forecasts, the desired forecast accuracy, measured in terms of P95 of the absolute percentage error is 10%.
For day-ahead generation forecasts, the desired forecast accuracy is P95 of 15%.

Minimum Metric for Forecasting Error Calculation:

P95 Error Computation

Step 1:

$$APE_t = \left| \frac{(At + Xt) - Ft}{C_t} * 100 \right|$$

where APE_t is the absolute percentage error,
A_t is Actual net generation in MW,
X_t is curtailment in MW due to transmission congestion or other reasons,
F_t is forecast in MW,
C_t is the available capacity in MW, and
t is a time block.
C_t is the difference between contracted capacity and capacity under maintenance in time block t.

Step 2:

- Daily P95 - Create a daily time series of $\{APEt, t=1\ to\ 24\}$, and compute the daily P95 using this time series
- Monthly P95 - Create a monthly time series of $\{APEt, t=1\ to\ 24*n\}$, where n is the number of days in the month. The monthly P95 is computed using this time series.
- Annual P95 - Create the yearly time series of $\{APEt, t=1\ to\ 24*365\}$. The annual P95 is computed using this time series.

SDC 2. **DISPATCH AND CONTROL**

SDC 2.1. **Introduction**

In real time operation, the System Operator (SO) shall Dispatch and Control the available Supply and Demand resources to serve the power and energy demand on the National Grid. The Scheduling and Dispatch Code (SDC 2) defines the roles and responsibilities of the SO and other relevant Code Participants in this respect and also sets out the procedure that the SO will follow to issue Dispatch Instructions to different Users pursuant to the "Indicative Operations Schedule" developed in SDC1.

SDC 2.2. **Objectives**

SDC 2.2.1. The objectives of SDC2 are to establish the process, guidelines and procedures:

(a) to issue Dispatch Instructions by the SO to Generators, ESUs in respect of their supply or demand, Demand Side Unit, and/or Interconnector; and

(b) to enable (as far as practicable), the SO to match Supply and Demand in real time while maintaining adequate Operating Reserves to ensure the Reliability, Security, and Safety of the Transmission System.

SDC 2.2.2. The SO will use SCED principles to achieve the objectives of this SDC2.

SDC 2.3. **Scope**

SDC2 applies to the SO, and the following Users:

(a) Centrally-Dispatched Generating Units (CDGUs):

(i) Conventional Generator (thermal, hydro, nuclear, bagasse, and concentrated-solar power Generators (CSP), etc.); and

(ii) VRE Generator (run-of-the-river hydro, solar, and wind, etc.)

(b) Energy Storage Units with respect to their supply to or demand on the Transmission System;

(c) Market Operator (MO);

(d) Transmission Network Operators;

(e) Interconnectors;

(f) Distribution Companies/Suppliers/BPCs and Transmission Connected Consumers; and

(g) Small/Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO).

SDC 2.4. **Procedure**

SDC 2.4.1. **Information to be Used**

SDC 2.4.1.1. The SO shall assess as to which User to Dispatch, based on the real time System conditions and factors as listed in SDC 1.4.12.2.

SDC 2.4.1.2. Except as provided below, the SO shall Dispatch the Scheduled resources strictly in accordance with those specified in the IOS developed under SDC1.

SDC 2.4.1.3. Additional factors which the SO shall also take into consideration when issuing Dispatch Instructions are the effect of those Users which have not partially or fully complied with the Dispatch Instructions of the SO, deviations of VRE Generation from the forecasts, or Special Actions (including Demand Control) pursuant to SDC (2.5.9), Testing or Investigations carried out under OC 11, unforeseen outages, and variation between forecast and actual Demand on the System.

SDC 2.5. **Dispatch Instructions**

SDC 2.5.1. **Introduction**

SDC 2.5.1.1. Dispatch Instructions relating to a Schedule Day will normally be issued at any time during the period beginning immediately after publication of the IOS. The SO may, however, at its discretion, issue Dispatch Instructions to a User prior to the publication of IOS, if considered necessary.

SDC 2.5.1.2. A Dispatch Instruction may be subsequently cancelled or changed as per real time System conditions.

SDC 2.5.1.3. Dispatch Instructions to User(s) will always be issued to the relevant Control Facility.

SDC 2.5.1.4. The SO will issue Dispatch Instructions directly to a:

(a) Generator for the Dispatch of its Generating Unit(s);

(b) Demand Side Unit, in respect of its Demand Control or Demand Response (as applicable);

(c) ESUs in respect of their supply to or demand on the Transmission System; and/or

(d) Interconnector for the Dispatch of its Interconnector transfers.

SDC 2.5.1.5. The SO may issue Dispatch Instructions for any facility of the User which has been declared Available in an Availability Notice even if that facility was not included in the IOS.

SDC 2.5.1.6. To add clarity, some examples of forms of and terms to be used by the SO in issuing Instructions are set out in the Appendix-A of this SDC2.

SDC 2.5.2. **Dispatch Instruction to Generators/Interconnectors**

Generator/Interconnectors shall adhere to the following:

(a) Dispatch Instruction to a Conventional Generator for a specific Generating Unit and/or Interconnector may involve a change in the Active Power output, a change in the Reactive Power output, Synchronizing and De-synchronizing time (if appropriate), a change of the mode of operation or fuel, or to provide one or more of the System Services.

(b) Dispatch Instruction to VRE Generators may involve a curtailment or increase in the Active Power output (subject to their primary resource availability), or to provide one or more of the contracted System Services. In case of run-of-the-river hydro plants, SO shall determine whether the plant shall be operated on constant-level mode or whether the pondage will be used for peaking/Frequency Control. However, the applicable limits of pond operation and environmental/irrigation obligations shall be fulfilled.

(c) Dispatch Instruction to an Interconnector (HVAC/HVDC) may involve, where applicable, a change in the Active Power flow (quantum and direction), a change in the Reactive Power exchange, Synchronizing and De-synchronizing time, a change of mode of operation, a change of the control mode, adjustment of control mode parameters and associated set-points, and/or to provide one or more of the System Services while considering the relevant Agreement(s).

(d) As Demand and Availability of resources varies during real-time operation, the SO will adjust Generating Unit/Interconnector MW level by using an economic loading order (as applicable) by following the principles of SCED in conjunction with relevant Agreement(s).

(e) Dispatch Instruction issued shall always be in accordance with Technical Parameters but shall take into account any temporary changes to these Parameters notified to the SO under SDC 1.4.10.2.

(f) A Dispatch Instruction issued by the SO to a Generator/Interconnector may be issued through Electronic Interface, verbally by phone, or by fax in accordance with the procedures detailed in OC 9.

(g) A Dispatch Instruction must be formally acknowledged immediately by the Generator in respect of its Generating Unit(s) or Interconnector by using the Electronic Interface, or in its absence, by telephone or fax, or a reason given to the SO immediately for non-acceptance or partial acceptance. The reason for non-acceptance may only be on Safety grounds (relating to personnel or Plant) or if the Dispatch Instruction is not considered valid by the Generator/Interconnector as further detailed in (h) below.

(h) For a Dispatch Instruction to be valid, it must observe the limits of Availability, System Service capability and Technical Parameters, as properly Declared to the SO in accordance with the provisions of this SDC relevant to the time and period to which the Dispatch Instruction relates, subject to System Emergency Condition as laid down in SDC 2.5.2.5.

(i) In the event that two or more CDGUs/Interconnectors have the same "Variable Operating Cost" and the SO is unable to differentiate on the basis of the factors identified in SDC 1.4.12.2, the SO shall select for Dispatch first the Generator/Interconnector which in SO's judgement is the most appropriate under the circumstances and prevailing conditions of the Schedule Day.

(j) When the identical CDGUs mentioned in (i) above are at the same Site, the Generator may notify the SO as to the preferred Unit to Dispatch. The SO shall however, select the Unit for Dispatch, taking into account its obligations in operating the Transmission System.

(k) When complying with Dispatch Instructions for a CCGT station, a Generator will operate its CCGT Units in accordance with the applicable CCGT Installation Matrix.

(l) In the event that in carrying out the Dispatch Instruction, an unforeseen problem arises, caused on Safety grounds (relating to personnel, property, or Plant), the Generator/Interconnector will notify the SO by telephone without delay.

SDC 2.5.2.1. **Synchronizing and De-Synchronizing Instructions**

SDC 2.5.2.1.1. Except in an emergency or by prior agreement, Synchronization or De-synchronization of a CDGU/Interconnector with or from the System shall only be carried out as a result of a Dispatch Instruction issued by the SO.

SDC 2.5.2.1.2. The SO shall determine the required Synchronizing and De-Synchronizing times for the CDGUs/Interconnector in accordance with the times Declared in their Technical Parameters and will issue Dispatch Instructions to Generators/Interconnectors accordingly. With the prior mutual consent of the SO and the Generator/Interconnector, the specified Synchronizing or De-synchronizing time in a Dispatch Instruction may vary from the Declared Technical Parameters, if it is practicable for the CDGU/Interconnector and acceptable to the SO.

SDC 2.5.2.1.3. If a Dispatch Instruction to a specific CDGU/Interconnector does not contain a MW level to be achieved, then it shall be assumed that the Dispatch Instructions is to set the MW level (following Synchronization) up to the Minimum Stable Level of the CDGU/Interconnector (as applicable).

SDC 2.5.2.1.4. Where the SO issues a Synchronizing time to a Generator/Interconnector for a specific Generating Unit/Interconnector, and the Generator/Interconnector finds that the Generating Unit/Interconnector will not be able to Synchronize within (±10) ten minutes of the instructed Synchronizing time, the Generator/Interconnector will immediately inform the SO of the situation and provide a new estimate of the Synchronizing time.

SDC 2.5.2.1.5. When a CDGU/Interconnector fails to Synchronize or trips before reaching Minimum Stable Level at the time mentioned in the Dispatch Instruction to Synchronize (where applicable), then the CDGU/Interconnector will not Synchronize with the System until a new Dispatch Instruction is issued by the SO for this purpose.

SDC 2.5.2.1.6. In the case of a CDGU capable of firing on different fuels, the Dispatch Instruction will also specify the fuel to be used by the Generator. If no fuel is stated in the Dispatch Instruction, then the most economical fuel available shall be used. The Generator will only be permitted to change Fuels with the SO’s prior consent.

SDC 2.5.2.1.7. For a CCGT, an instruction may specify the Cycle Operating Mode and/or an Instruction to Dispatch one or more of the CCGT Units in Open Cycle Mode. The Generator must then ensure that its CCGT Station achieves the new operating mode, without undue delay and in accordance with that CCGT’s declared Availability and Technical Parameters.

SDC 2.5.2.1.8. The instruction to Synchronize a CDGU with the System, unless otherwise specified by the SO at the time of giving the Dispatch Instructions, shall be deemed to include an automatic instruction of Operating Reserve, the level of which is to be provided in accordance with the applicable provisions of OC.5.4

SDC 2.5.2.1.9. A VRE Generator shall, through appropriate necessary Equipment, be capable of smooth Synchronization and de-Synchronization, without causing jerk(s) on the Transmission System.

SDC 2.5.2.2. **Dispatch of Active Power**

SDC 2.5.2.2.1. Based on the IOS, on System conditions, and on other factors as may arise from time to time, the SO will issue Dispatch Instructions to a Generator in relation to a specific CDGU or Interconnector, which is Synchronized with the System, to adjust its Active Power output at a Target Frequency.

SDC 2.5.2.2.2. The SO shall determine the required times for achieving the Instructed MW levels of the CDGUs/Interconnectors in accordance with their declared Technical Parameters and will issue Dispatch Instructions to Generators/Interconnectors accordingly. With mutual consent of the SO and the Generator/Interconnector, the specified time to achieve the target output in a Dispatch Instruction may vary from the Declared Technical Parameters, if practicable for the CDGU/Interconnector.

SDC 2.5.2.2.3. On receiving a Dispatch Instruction to change the level of Active Power, the Generating Unit/Interconnector must, without any delay, adjust the MW level of the CDGU/Interconnector to achieve the new target within that Generating Unit's/Interconnector's Declared Technical Parameters.

SDC 2.5.2.2.4. A Generating Unit/Interconnector shall be deemed to have complied with a Dispatch Instruction when it achieves a MW level within the allowable tolerance (as per the applicable agreement) of the Instructed MW level and within the time calculated for the change as per its Declared Technical Parameters.

SDC 2.5.2.2.5. The adjustment of Active Power level of a CDGU/Interconnector operating in a Frequency Sensitive Mode for System frequency other than an average of 50 Hz, shall be made in accordance with the current declared value of the droop setting of the Governor Droop for Conventional Generating Units/HVAC Interconnectors, or Active Power Frequency Regulation for VRE Generating Units, or Frequency Limit Control for HVDC Interconnectors.

SDC 2.5.2.2.6. The Dispatch Instructions for Active Power at the Connection/Delivery Point will be made with due regard to any resulting change in Reactive Power capability and may include instruction for reduction in Active Power generation to enable an increase in Reactive Power capability.

SDC 2.5.2.2.7. In addition to instructions relating to the Dispatch of Active Power, Dispatch Instructions (unless otherwise specified by the SO at the time of giving the Dispatch Instructions) shall be deemed to have included an automatic instruction of Primary Operating Reserve, and voltage/reactive support, the level of which is to be provided in accordance with OC 5 and the System (Ancillary) Service Agreement (as applicable) and system stability control facilities (such as Power System Stabilizer, Power Oscillation Damper etc.) as specified in Connection Code.

SDC 2.5.2.3. **Dispatch of Reactive Power**

SDC 2.5.2.3.1. To ensure that a satisfactory voltage profile is maintained in the System and that sufficient Reactive Power reserves are maintained, the SO may issue Dispatch

Instructions in relation to Reactive Power (with due regard to the Technical Parameters).

SDC 2.5.2.3.2. **MVAR output:** Where a Generating Unit/Interconnector is instructed to achieve a specific output (at instructed MW level), the Generator/Interconnector shall achieve that output within a tolerance of (±2%) two percent or one (±1) MVAR (or such other figure as may be agreed with the SO) by:

(a) tap changing on the Generating Unit step-up transformer;
(b) adjusting the set-point of the Generating Unit's Automatic Reactive Power Regulator or Automatic Voltage Regulator;
(c) operation of any other reactive compensation equipment available on Generation Site/Interconnector; or
(d) Q-Control mode of HVDC Interconnector (manual or automatic).

SDC 2.5.2.3.3. Once this has been achieved, the Generator/Interconnector will not tap change or adjust the set-point of the Generating Unit's Automatic Voltage Regulator or change Q-Control parameters (as applicable) without prior consent of the SO, on the basis that MVAR output will be allowed to vary with System conditions.

SDC 2.5.2.3.4. Where a Generating Unit/Interconnector is instructed to a specific target voltage (at target MW level), the Generator/Interconnector shall achieve that target within a tolerance of one (±1) kV (or such other figure as may be agreed with the SO) by either:

(a) tap changing on the Generating Unit step-up transformer;
(b) adjusting the set-point of the Generating Unit's Automatic Voltage Regulator;
(c) operation of any other reactive compensation equipment available on Generation/Interconnector Site; or
(d) U-Control mode of HVDC Interconnector (manual or automatic).

SDC 2.5.2.3.5. Under normal operating conditions, once this target voltage level has been achieved, the Generators/Interconnectors will not tap change or adjust terminal voltage or change U-Control parameters (as applicable) again without the prior consent of the SO.

SDC 2.5.2.3.6. **Maximum MVAR production ("maximum Excitation" for Synchronous Generating Units):** Under certain conditions, such as low System voltage, an instruction to maximum MVAR output (or "maximum Excitation" for Synchronous Generating Units) at instructed MW output may be given, and a Generator/Interconnector shall take the required action(s) to maximize MVAR output.

SDC 2.5.2.3.7. **Maximum MVAR absorption ("minimum Excitation" for Synchronous Generating Units):** Under certain conditions, such as high System voltage, an instruction to maximum MVAR absorption at instructed MW output (or "minimum Excitation" for Conventional Generating Units) may be given, and a Generator/Interconnector shall take the required action(s) to maximize MVAR absorption.

SDC 2.5.2.3.8. The Automatic Reactive Power or Automatic Voltage Regulator of Generators shall 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 expressly agreed otherwise with the SO. In the event of any change in System voltage, Generators shall not take any action to override automatic MVAR response which is produced as a result of constant terminal voltage mode of operation unless instructed otherwise by the SO or unless immediate action is necessary to maintain the stability limits.

SDC 2.5.2.3.9. In the event of a sudden change in System voltage, a Generator/Interconnector must not take any action to override automatic MVAR response unless instructed otherwise by the SO or unless immediate action is necessary to maintain the stability limits or to avoid an imminent risk of injury/damage to persons, property, or Plant/equipment.

SDC 2.5.2.3.10. A Dispatch Instruction relating to Reactive Power will be implemented without any delay and will be achieved not later than two (2) minutes after the instructed time, or such longer period as the SO may instruct.

SDC 2.5.2.3.11. On receiving a new Active Power Dispatch Instruction, no tap changing, or Generator terminal voltage adjustment shall be carried out to change the MVAR unless there is a new Dispatch Instruction.

SDC 2.5.2.3.12. Where an instruction to Synchronize a CDGU is given, or where a Generating Unit is Synchronized and a MW Dispatch Instruction is given, a MVAR Dispatch Instruction consistent with the Generating Unit's relevant parameters will also be given. In the absence of a MVAR Dispatch Instruction with an instruction to Synchronize, the MVAR output should be zero (0) MVAR.

SDC 2.5.2.3.13. Where a Dispatch Instruction to De-synchronize a CDGU is given, a MVAR Dispatch Instruction, compatible with Shutdown, may also be given prior to De-Synchronization being achieved. In the absence of a separate MVAR Dispatch Instruction, it is implicit in the Dispatch Instruction to De-Synchronize that MVAR output should at the point of synchronism be zero (0) MVAR at De-Synchronization.

SDC 2.5.2.4. **Additional Dispatch Instructions**

SDC 2.5.2.4.1. **Reserve:** Details of the reserve to be provided by each Generating Unit/ Interconnector including specification of the timescale in which that reserve may be transferable into increased Generating Unit/Station output;

SDC 2.5.2.4.2. **System (Ancillary) Services:** An instruction for a User to provide System (Ancillary) Services;

SDC 2.5.2.4.3. **Secondary Control Mode:** A requirement for change to or from Secondary Control Mode for each Generating Unit;

SDC 2.5.2.4.4. **Testing or Monitoring:** To carry out Testing, Monitoring or Investigations as required under OC.11, or Testing at the request of a User under OC.10, or Commissioning Tests under the CC 12; or to carry out a System Test as required under OC.10.

SDC 2.5.2.4.5. **Fuel:** Fuel to be used by the Generator in operating the CDGUs.

SDC 2.5.2.4.6. Dispatch Instruction could also be issued:

(a) to switch into or out of service a Special Protection Scheme or other Inter-tripping Scheme or Stability Control System (SCS) strategy.

(b) for a Generating Unit to operate in Synchronous Condenser mode (where contracted and is considered necessary by the SO);

SDC 2.5.2.4.7. **Energy Storage Unit:** mode changes for ESU, where contracted, in relation to ESU Generation or Demand.

SDC 2.5.2.5. **Dispatch Instructions under Emergency Conditions**

SDC 2.5.2.5.1. In order to maintain Transmission System integrity under System Emergency Conditions, the SO may issue Dispatch Instructions to Generators/Interconnectors to operate outside the limits specified in their current Technical Parameters or Availability Notice. When issuing such a Dispatch Instruction, the SO shall inform the Generator/Interconnector that the Dispatch Instruction is being issued under System Emergency Conditions.

SDC 2.5.2.5.2. Where the SO has issued a Dispatch Instruction in accordance with the provisions for System Emergency Conditions requiring operation of a CDGU/Interconnector outside the limits specified in their current Technical Parameters or Availability Notice, then the Generator/Interconnector shall comply with the Dispatch Instructions.

SDC 2.5.2.5.3. The De-Synchronization of a CDGU/Interconnector following the operation of a Special Protection Scheme/Stability Control System strategy selected by the SO shall be deemed to have happened as a result of a Dispatch Instruction issued by the SO.

SDC 2.5.2.6. **Changes to Technical Parameters**

SDC 2.5.2.6.1. Each Generator/Interconnector shall notify to the SO without delay by telephone of any change or loss (temporary due to a defect) to the operational capability including any changes to the Technical Parameters of each CDGU/Interconnector.

SDC 2.5.2.6.2. If, for any reason, including a change of Availability or Technical Parameters made by the Generator/Interconnector, the prevailing Dispatch Instruction in respect of any CDGU/Interconnector is no longer within the applicable Availability or Technical Parameters then the Generator/Interconnector will use reasonable endeavors to secure that a revised Dispatch Instruction is issued by the SO such that the new Dispatch Instruction is within the new applicable Availability and/or Technical Parameters;

SDC 2.5.2.6.3. If the SO fails to issue such new Dispatch Instruction in accordance with SDC 2.5.2.6.2 within a reasonable time, then the relevant Generator/Interconnector shall be entitled to change the operation of its such CDGU/Interconnector to bring its operation within the applicable Availability and/or Technical Parameters until the SO issues a new Dispatch Instruction within the applicable Availability and/or Technical Parameters. Prior to making such a change in operation, the Generator/Interconnector will use reasonable endeavors to inform the SO (by electronic mode, or by telephone and then confirming it by fax) of its intended action and the timing of the intended action.

SDC 2.5.2.7. **Target Frequency**

SDC 2.5.2.7.1. Dispatch Instructions to Generators/Interconnector will generally indicate the target MW (at Target Frequency) to be provided at the Connection/Delivery Point to be achieved in accordance with the Technical Parameters.

SDC 2.5.2.7.2. Dispatch Instructions deemed to be given upon the operation of an agreed Low Frequency Relay will be deemed to indicate the target MW (at Target Frequency), which may be either at maximum MW Output or at some lower MW Output (as previously specified by the SO), to be provided at the Connection Point which reflects and is in accordance with the Technical Parameters and/or parameters as revised by the SO in its Dispatch Instruction.

SDC 2.5.2.8. Subject only to SDC (2.5.2.10) and SDC (2.5.2.11), Dispatch Instructions will not be inconsistent with the Availability and/or Technical Parameters and/or other relevant data notified to the SO under SDC1 (and any revisions under SDC1 to that data).

SDC 2.5.2.9. A new Dispatch Instruction may be subsequently given (including an instruction for a cancelled start) at any time.

SDC 2.5.2.10. Dispatch Instructions may, however, be inconsistent with the Availability and/or Parameters for the purposes of carrying out a test or System Test at the request of the relevant Generator under OC 10, to the extent that such Dispatch Instructions are consistent with the procedure agreed (or otherwise determined) for conducting the test or System Test (as the case may be).

SDC 2.5.2.11. For the avoidance of doubt, any Dispatch Instruction(s) issued by the SO for the purpose of carrying out a test or System Test at the request of the relevant Generator/Interconnector under OC 10 shall not be considered a Dispatch Instruction given pursuant to this SDC2.

SDC 2.5.2.12. To preserve System integrity under emergency circumstances where, for example, the SO cannot meet its License condition, the SO may issue a Dispatch Instruction to change Generating Unit output, Demand Response/Control block, Interconnector transfers even when this is outside the parameters registered or amended. This may, for example, be an instruction to trip or partially load a Generating Unit. The Dispatch Instruction will clearly state that it is being issued by the SO pursuant to emergency circumstances under SDC 2.5.2.11.

SDC 2.5.2.13. If a Generator/Interconnector is unable to comply with any Dispatch Instruction due to some compelling reasons, the Generator/Interconnector must immediately inform the SO of such reasons and provide justifications for its non-compliance.

SDC 2.5.3. **Dispatch Instructions for Frequency Control**

SDC 2.5.3.1. When the SO determines it is necessary, by having monitored the System Frequency, it may, as part of the procedure set out in OC 5, issue a Dispatch Instruction (including Target Frequency where applicable) in order to seek to regulate Frequency to meet the requirements for Frequency Control. The SO will give, where applicable, 15 minutes notice to each relevant User of variation in Target Frequency.

SDC 2.5.3.2. Target System Frequency changes shall normally only be 49.95, 50.00, 50.05Hz (at an interval of 0.05 Hz).

SDC 2.5.3.3. When the System Operator determines it is necessary, by having monitored the System Frequency, it shall, as a part of the procedure set out in SDC 2, issue Dispatch Instructions including the instructions for Secondary Operating Reserve, in order to regulate the System Frequency to meet the requirements for Frequency Control as contained in the OC 5. The CDGUs to be selected by the System Operator for Secondary Frequency Control shall be instructed by the System Operator to operate at the Target System Frequency, which shall be 50.00 Hz.

SDC 2.5.3.4. The Dispatch Instruction for Secondary Frequency Control shall include the range (AGC Maximum and AGC Minimum), being a registered Technical Parameter.

SDC 2.5.3.5. All variations in MW Output of Generators/Interconnectors in response to Frequency Control shall be deemed as Dispatch Instructions.

SDC 2.5.3.6. The System Operator may allocate a part of the requirements for Operating Reserve to Gas Turbine CDGUs with the capability of Low Frequency Relay initiated response (if applicable) for start-up to a pre-determined output level which have not been Scheduled for Dispatch in accordance with SDC 1, although the System Operator may, in the event, decide to issue a Dispatch instruction in respect of any of such CDGU in accordance with SDC 2. Alternatively, Gas Turbine CDGUs of this type may be Scheduled for Dispatch by the System Operator in accordance with SDC 1.

SDC 2.5.3.7. The System Operator shall periodically specify, within the range established pursuant to the relevant Agreement(s), Low Frequency Relay settings to be applied to the CDGUs pursuant to OC 5.4.4 and shall instruct the Low Frequency Relay initiated response to be placed in and out of service.

SDC 2.5.3.8. All Generators shall comply with System Operator's instructions issued under SDC 2.5.3.7 for Low Frequency Relay settings. The Generators shall not alter such low frequency relay settings or take low frequency initiated response out-of-service without the System Operator authorization, except where necessary, in the Generator's reasonable opinion, to avoid an imminent risk of injury to persons or material damage to property (including the CDGU) with the authorization of the System Operator.

SDC 2.5.3.9. The System Operator shall endeavor (in so far as it is able to) control electric clock time to within plus or minus 10 seconds of Standard Time by specifying changes to target the System Frequency, and by Dispatch taking into account Variable Operating Cost and forecast Generator/load demand margins. Errors greater than plus or minus 10 seconds may be temporarily accepted at the System Operator’s reasonable discretion. The System Operator shall give 15 minutes notice to each Generator of variation in Target System Frequency.

SDC 2.5.4. **Dispatch Instruction to DSUs**

SDC 2.5.4.1. Dispatch Instructions to DSUs relating to the Schedule Day will normally be issued at any time during the period beginning immediately after the publication of the IOS as a list of Special Actions in respect of that Schedule Day.

SDC 2.5.4.2. The SO will issue Dispatch Instructions directly to the DSU at its designated Control Centre in relation to Special Actions, Demand Control, or Demand Response as may be the case.

SDC 2.5.4.3. Dispatch Instructions may include:

(a) a requirement for Demand Reduction, Disconnection, or Restoration;

(b) an instruction for load transfer between some Connection Points; and

(c) an instruction to switch in the load-shedding scheme.

SDC 2.5.4.4. The DSU shall comply without delay with all the Dispatch Instructions received by it. In the event that in carrying out the Dispatch Instructions, an unforeseen problem arises, the DSU will notify the SO by telephone without delay.

SDC 2.5.4.5. The Dispatch Instruction delivered verbally (by phone) shall be followed by a written confirmation afterwards.

SDC 2.5.5. **Standing Instructions**

SDC 2.5.5.1. The SO may notify a User that in certain circumstances it requires the User to operate in accordance with a Standing Instruction, which shall be deemed to be given when the circumstances arise. These Standing Instructions may include, for example, how to operate if the System Operator loses the ability to direct the operation and control of the Transmission System temporarily, in the circumstances envisaged under OC 9 where the System Operator is unable for any reason, pending the transfer of system operations to a temporary Control Centre.

SDC 2.5.5.2. The SO shall not, by means of a Standing Instruction, require any of the Users to be Dispatched in a manner in which the SO would not have access or be able to exercise option to require such facilities to be Dispatched by means of a Dispatch Instruction issued in accordance with this SDC2.

SDC 2.5.6. **Action required by Users**

SDC 2.5.6.1. Each User shall comply in accordance with SDC 2.5.6 with all Dispatch Instructions issued by the SO, except where the User has contested the SO under the provisions of SDC 2.5.2 (g) for the invalidity of the Dispatch Instructions.

SDC 2.5.6.2. A CDGU shall not, however, be in default in complying with the Dispatch Instructions, if, subsequent to the issuance of the Dispatch Instruction, the CDGU and the System Operator agree on an early or late synchronization, and the CDGU synchronizes the relevant Unit in accordance with that agreement.

SDC 2.5.7. **Implementation of Dispatch Instructions by Users**

SDC 2.5.7.1. A User shall take the required action on a Dispatch Instructions issued by the SO immediately and without any undue delay, including the Instructions issued pursuant to SDC 2.5.2.5.

SDC 2.5.7.2. Except as specified in SDC 2.5.7.2 below, Generators/Interconnectors shall Synchronize or de-Synchronize their CDGUs/Interconnectors on the Dispatch Instructions of the SO only or when Synchronization or de-Synchronization (as the case may be) occurs automatically as a result of activation of a Special Protection Scheme or an Under- Frequency Relay.

SDC 2.5.7.3. Except as specified below in SDC 2.5.7.3, DSUs will reduce or increase their Demand Response to the Dispatch Instructions of the SO only or when it occurs automatically as a result of activation of a Special Protection Schemes or Under-Frequency Relay operations.

SDC 2.5.7.4. De-Synchronization may be permitted without Instruction by SO only if it is to avoid, in the Generator's/Interconnector's reasonable opinion, an imminent risk of injury or damage to persons, or property, or Plant.

SDC 2.5.7.5. A DSU may be excused from fully complying with a Dispatch Instruction by the SO for a Demand Response commitment only, if it is to avoid, in that DSU's reasonable opinion, an imminent risk of injury/damage to persons, property, or Plant.

SDC 2.5.7.6. If any exceptions occur, pursuant to SDC 2.5.7.4 or SDC 2.5.7.5, then the relevant User will inform the SO immediately about the exception, explaining the circumstances which led to the situation. The SO may require the relevant User to support its claim with acceptable evidence for the stated exception.

SDC 2.5.7.7. When necessary, the SO shall issue dispatch instructions for a Black Start activation pursuant to OC (5).

SDC 2.5.8. **Minimum Demand Regulation ("MDR")**

Synchronized CDGUs must at all times be capable of reducing their output sufficiently to allow adequate Operating Reserve for Frequency Control in the Transmission System. The SO shall monitor the output of the Synchronized Generating Units against the demand being experienced on the System to ascertain whether the level of MDR in the System is sufficient, and may take any shortfall into account in altering the Dispatch.

SDC 2.5.9. **Special Actions**

SDC 2.5.9.1. The SO may, as part of a Dispatch instructions, issue instructions for Special Actions (either pre- or post-¬fault) to a User in respect of any of its facilities, in the event that the SO believes that such instructions are necessary to maintain the Integrity, Security, or Stability of the Transmission System.

SDC 2.5.9.2. For a Generator, such Special Actions may involve a load change or a change of required Notice to Synchronize, in a specific timescale on individual or group of Generating Units basis.

SDC 2.5.9.3. For a DSU, these Special Actions may involve load transfers between the Connection Points or arrangements for Demand Control by manual or automatic means.

SDC 2.6. **Dispatch against IOS**

Based on the factors mentioned in SDC 2.4, actual Dispatch carried out by SO in real-time may differ from the IOS published for the Schedule Day. SO shall maintain regular comparison logs for differences between IOS and actual Dispatch.

Dispatch Instructions for CDGUs and Demand Side Unit

General

This Appendix A to SDC2 provides further information on the form of a Dispatch Instruction as well as an example of a Dispatch Instruction for CDGUs and Demand Side Units.

Form of Dispatch Instruction

All Loading/De-Loading Rates shall be assumed to be in accordance with Technical Parameters. Each Dispatch Instruction shall, wherever possible, be kept simple, drawing as necessary from the following forms and SDC2.4.2.

The Dispatch Instruction given by Electronic Interface, telephone, or facsimile transmission shall normally follow the form:

a. where appropriate, the specific CDGU User's Plant to which the instruction applies;
b.
    i. the MW Output (or Demand Side Unit MW Response) to which it is instructed; or
    ii. the MW Output (or Demand Side Unit MW Response) to which it is instructed until, a specified time, in which case the instructed MW Output shall be followed until a further Dispatch Instruction is issued;
c. if the start time is different from the time the instruction is issued, the start time shall be included;
d. where specific Loading/De-Loading Rates are concerned, a specific target time;
e. the issue time of the instruction;
f. the designated fuel and/or declared fuel
g. in the case of CDGUs , if the instruction is designated as a "Peak Instruction", this shall be stated; and
h. in the case of a CCGT Installation, the operating mode to which it is instructed.

The dispatch instruction given by Instructor shall normally follow the form:

a. The specific CDGU to which the instruction applies, if the Instructor is on a unit basis or the group of CDGUs to which the instruction applies;
b. The Output to which it is instructed.

Any dispatch instruction relating to the designated fuel and/or declared fuel, (or fuel) as the case may be, shall be given by telephone, electronically or by facsimile transmission.

Dispatching a Synchronized CDGU to increase or decrease MW Output

If the time of the Dispatch Instruction is 1400 hours, the Unit is Unit 1 and the MW Output to be achieved is 205 MW, the relevant part of the instruction would be, for example:

"Time 1400 hours. Unit 1 to 205 MW until further notice" Or,

"Time 1400 hours. Unit 1 to 205 MW effective until 1500 hours"

If the start time is 1415 hours, it would be, for example:

"Time 1400 hours. Unit 1 to 205 MW until further notice, start at 1415 hours" Or

"Time 1400 hours. Unit 1 to 205 MW effective until 1500 hours, start at 1415 hours"

Loading and De-Loading Rates are assumed to be in accordance with Technical Parameters unless otherwise stated. If different Loading or De-Loading Rates are required, the time to be achieved shall be stated, for example:

"Time 1400 hours. Unit 1 to 205 MW by 1420 hours"

Dispatching a CDGU to Synchronize/de-Synchronize

CDGU Synchronizing

In this instance, for CDGUs, the Dispatch Instruction issue time shall always have due regard for the synchronizing Start-Up Time (for cold, hot, warm states) declared to the SO by the Generator as a Technical Parameters.

The instruction shall follow the form, for example:

"Time 1300 hours. Unit 1, Synchronize at 1600 hours"

In relation to an instruction to Synchronize, the Synchronizing time shall be deemed to be the time at which synchronization is to take place.

Unless a loading program is also given at the same time it shall be assumed that the CDGU(s) are to be brought to Minimum Generation and on the Generator reporting that the unit has Synchronized, a further Dispatch Instruction shall be issued.

When a Dispatch Instruction for a CDGU to Synchronize is cancelled (i.e. a Cancelled Start) before the unit is Synchronized, the instruction shall follow the form, for example:

"Time 1400 hours. Unit 1, cancel Synchronizing instruction"

CDGUs De-Synchronizing

The Dispatch Instruction shall normally follow the form, for example:

"Time 1300 hours. Unit 1, Shutdown"

If the instruction start time is for 1400 hours the form shall be, for example:

"Time 1300 hours. Unit 1, Shutdown, start at 1400 hours"

Both the above assume De-Loading Rate at declared Technical Parameters. Otherwise the message shall conclude with, for example:

"... and De-Synchronize at 1500 hours"

Dispatch Instructions to HVDC.

The Dispatch Instruction to HVDC (Interconnector/Embedded) shall normally follow the form, for example:

"Start/ deblock operation of HVDC pole in Q-Mode, Bipole Power Mode with Ground Return with Normal Voltage Mode" or

"Increase Bipole Dispatch to 1500 MW at the rate 100 MW/min" or

"Stop/ block operation of HVDC pole" or

"Change of DC power flow direction from Station A to Station B" etc.

Frequency Control

All the above Dispatch Instructions shall be deemed to be at the instructed Target Frequency, i.e. where a CDGU is in the Frequency Sensitive Mode instructions refer to target MW Output at Target Frequency. Target Frequency changes shall always be given to the Generator by telephone or Electronic Interface and shall normally only be 49.95, 50.00, 50.05Hz.

The adjustment of MW Output of a CDGU for System Frequency other than an average of 50 Hz, shall be made in accordance with the current Declared value of Governor Droop for the CDGU.

CDGUs required to be Frequency insensitive shall be specifically instructed as such. The Dispatch Instruction shall be of the form for example:

"Time 2100 hours. Unit 1, to Frequency insensitive mode"

Frequency Control instructions may be issued in conjunction with, or separate from, a Dispatch Instruction relating to MW Output.

Emergency Load Drop

The Dispatch Instruction shall be in a pre-arranged format and normally follow the form, for example:

"Time 2000 hours. Emergency Load drop of "X"MW in "Y" minutes"

Voltage Control Instruction

In order that adequate System voltage limits as specified in OC.5.5.7 are maintained under Normal and (N-1) conditions, a range of voltage control instructions shall be utilized from time to time, for example:

i. Operate to Nominal System Voltages;
ii. Operate to target Voltage of 132 kV;
iii. Maximum production or absorption of Reactive Power (at current instructed MW Output);
iv. Increase reactive output by 10 MVAR (at current instructed MW Output);
v. Change Reactive Power to 100 MVAR production or absorption;
vi. Increase CDGU Generator step-up transformer tap position by [one] tap or go to tap position [x];
vii. For a Simultaneous Tap Change, change CDGU Generator step-up transformer tap position by one [two] taps to raise or lower (as relevant) System Voltage, to be executed at time of telegraph (or other) Dispatch Instruction.
viii. Achieve a target Voltage of 210 kV and then allow to vary with System conditions;
ix. Maintain a target Voltage of 210 kV until otherwise instructed. Tap change as necessary.

It should be noted that the excitation control system constant Reactive Power level control mode or constant Power Factor output control mode shall always be disabled, unless agreed otherwise with the SO.

Instruction to change fuel

When the SO wishes to instruct a Generator to change the fuel being burned in the operation of one of its CDGUs from one Dispatched Fuel (or fuel) to another (for example from Gas to HSD), the Dispatch Instruction shall follow the form, for example:

"Time 1500 hours. Unit 2 change to HSD fuel at 1700 hours".

Instruction to change fuel for a dual firing CDGU

When the SO wishes to instruct a Generator to change the fuel being burned in the operation of one of its CDGUs which is capable of firing on two different fuels (for example, coal or oil), from one designated fuel (or fuel) to another (for example, from coal to oil), the instruction shall follow the form, for example:

"Time 1500 hours. Unit 1 generate using oil at 1800 hours".

Maximization/ Peak Instruction to CDGUs

When the SO wishes to instruct a Generator to operate a CDGU at a level in excess of its Availability, the instruction shall follow the form, for example:

"Peak Instruction. Time 1800 hours. Unit GT2 to 58 MW."

Emergency Instruction

If a Dispatch Instruction is an Emergency Instruction the Dispatch Instruction shall be prefixed with the words. This is an Emergency Instruction. It may be in a pre- arranged format and normally follow the form, for example:

“This is an Emergency Instruction. Reduce MW Output to "X"MW in "Y" minutes,
Dispatch Instruction timed at 2000 hours.

Dispatching a Demand Side Unit to a Demand Side Unit MW Response

For Demand Side Units, the Dispatch Instruction issue time shall always have due regard for the Demand Side Unit Notice Time declared to the SO by the Demand Side Unit Operator as a Technical Parameter.
If the time of the Dispatch Instruction is 1400 hours, the Demand Side Unit is XX1, the Demand Side Unit Notice Time is 10 minutes and the Demand Side Unit MW Response to be achieved is 20 MW, the relevant part of the instruction would be for example:

“Time 1400 hours. Unit XX1 to 20 MW until further notice, start at 1410 hours” Or
“Time 1400 hours. Unit XX1 to 20 MW until 1500 hours, start at 1410 hours. Or
Time 1400 hours. Unit XX1 to limit consumption to maximum 100 MW until further notice, start at 1410 hours”

PROTECTION AND CONTROL CODE

PCC 1. **INTRODUCTION**

This sub-code (PCC) specifies the requirements that are to be complied with by the Users to ensure System's Security, Reliability, and Stability of the National Grid by using necessary and appropriate Protection Schemes at their facilities, especially at the Connection Point.

Users shall be liable to meet minimum technical, design and operational criteria from protection perspective in order to protect the Transmission System and their Plant and Apparatus directly connected with it, and to maintain stable and secure operation of the Transmission System.

PCC 1.1. **Objectives**

The objective of the Protection & Control Code (PCC) is to detail the minimum technical and performance requirements for the Transmission System and Users, regarding their Protection Systems which include design, equipment, schemes, and coordination of these systems and associated devices and apparatus.

PCC 1.2. **Scope**

(a) This Code applies to SO and the following Users:

(i) Transmission Network Operators (TNOs);

(ii) National Grid Company (NGC, currently this is called NTDC)

(iii) Provincial/Regional Grid Companies (PGCs/RGCs)

(iv) Special Purpose Transmission License Companies (SPTLs)

(b) Distribution Companies (DISCOs)

(c) Generators connected to the Transmission System;

(d) Bulk Power Consumers connected to the Transmission System; and

(e) Interconnectors.

PCC 1.3. **Technical Standards**

PCC 1.3.1. User's Plant and Apparatus shall comply with Grid Code and NGC standards to meet the functional requirements of SO.

PCC 1.3.2. Where the SO/NGC, determines that in order to ensure safe and coordinated operation of a User's Plant and Apparatus with the Transmission System, there is a requirement for some supplemental specifications and/or more stringent standards to apply to the User's Protection System, the SO/NGC shall notify the User of such requirements and the User shall comply with these supplemental/additional requirements without undue delay.

PCC 2. **PROTECTION OF POWER SYSTEM EQUIPMENT**

PCC 2.1. **Introduction**

As per requirement, the Users shall provide necessary Protection of their Plant and Apparatus and equipment which shall include but not limited to the following:

(a) Bus-Bars

(b) Transmission lines

(c) Transformers

(d) Generators

(e) Shunt Reactor

(f) Circuit Breakers

(g) Grid Station auxiliary systems

(h) Interconnectors

PCC 2.2. **Types of Protection**

The requirements laid down hereunder stipulate the minimum requirement for the Protection System to be provided by Users for their facilities. More detailed and specific requirement for a particular User, if required, shall be determined and specified in the relevant Agreement.

The type of Protection may be segregated into Primary and Back-up Protections, as being used at multiple instances in this sub-code. The protective relaying schemes, which include but not limited to, shall be provided for the following (wherever applicable):

(a) 220 kV, 500 kV and higher voltage levels sub-station bus bars

(i) Bus Differential Protection (High Impedance / Low Impedance) with built-in End Zone Fault detection and clearing feature

(ii) Bus Coupler Protection

(iii) Lightning Protection

(b) 220 kV, 500 kV and higher voltage Transmission Lines

(i) Distance Protection Set-I, alternatively Differential Protection SET-I (Main)

(ii) Distance Protection Set-II, alternatively Differential Protection SET-II (Duplicate)

(iii) Transfer Trip including communication schemes

(iv) Over Current & Earth Fault Protection

(v) Line Current Differential Protection with built-in Multi Zone Distance Protection Set I (Main) (if applicable)

(vi) Line Current Differential Protection with built-in Multi Zone Distance Protection Set II (Duplicate) (if applicable)

(vii) Line Over Voltage Protection (Low Set, Inverse Set and High Set).

(viii) Line Open Circuit Fault (Broken Conductor) Protection

(ix) Auto-Recloser with built-in Synchronism Check feature

(x) Tele Protection Scheme

(xi) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xii) Lightning/Surge Arrestor for protection against surges

Multi-channel telecommunication system shall be provided between the Users' substation(s)/switchyard(s) for bi-directional telecommunication of Protection signals, in order to limit the effects of Power System disturbances/abnormalities, and clearance of system faults, with the required discrimination and speed.

Tele-protection schemes implemented at both ends should be compatible with each other and able to exchange tele protection signals without any issue.

The telecommunication infrastructure shall also be capable of sending and receiving any inter-trip signals required for Cross-Trip schemes to be implemented at Users' substation(s)/switchyard(s) as per the NGC standards and specifications, other sections of the Grid Code, and in the relevant Agreement(s).

(c) 765/500 kV, 500/220 kV and 220/132 kV Transformers

(i) Transformer Differential Protection

(ii) Impedance Protection

(iii) Under/Over Voltage Protection

(iv) Over Current & Earth Fault Protection (HV, LV, Tertiary)

(v) Neutral Over Current Protection

(vi) Over Flux Protection

(vii) Over Load Protection

(viii) Restricted Earth Fault (REF) Protection

(ix) High Impedance Restricted Earth Fault (REF) Protection

(x) Percentage Biased Transformer Differential Protection Set I (Main)

(xi) Percentage Biased Transformer Differential Protection Set II (Duplicate)

(xii) Sudden Pressure Protection

(xiii) Buchholz Protection

(xiv) Oil Temperature Protection

(xv) Winding Temperature Protection

(xvi) Pressure Relief Devices/Valves

(xvii) OLTC Protection

(xviii) AVR Control Scheme

(xix) Provision for Implementation of Cross-Trip/Special Protection Scheme

(xx) Fire Fighting Equipment System

(d) Generators

(i) Generator Differential Protection

(ii) Overall Differential Protection for Generator and Transformer

(iii) Generator Impedance/Distance Protection

(iv) Over Current & Earth Fault Protection

(v) Voltage-controlled Over Current Protection

(vi) Over/Under Voltage Protection

(vii) Loss of Excitation Protection

(viii) Over/Under Frequency Protection

(ix) Overload Protection

(x) Rate of Change of Frequency (ROCOF) Protection

(xi) Loss of Load (Load Rejection) protection Scheme for step-wise isolation of generators

(xii) Reverse Power Protection

(xiii) AVR Control Scheme

(xiv) Provision for Implementation of Cross-Trip/Special protection Scheme

(xv) Neutral displacement voltage detection for Generating Unit transformer

(xvi) Loss-of-Mains Protection (rate of change of frequency or vector shift)

(xvii) Pole Slip Protection and/or out of step and/or power swing

(e) Shunt Reactors

(i) Differential Protection

(ii) Impedance Protection

(iii) High Impedance Restricted Earth Fault (REF) Protection

(iv) Over Current & Earth Fault Protection

(v) Switch Synchronization/Point on Wave Switching Protection

(vi) Sudden Pressure Protection

(vii) Buchholz Protection

(viii) Oil temperature protection

(ix) Winding Temperature Protection

(f) Circuit Breakers

(i) Breaker-Fail Protection

(ii) Pole Discrepancy Protection

(iii) Trip Circuit Supervision Protection

(iv) Anti-pumping Protection

(v) Low Pressure Alarm & Lockout Protection

(vi) Over Current Protection for Bus Coupler Breaker

(g) Below 220 kV level Users

(i) Bus Differential Protection

(ii) Transformer Differential Protection

(iii) Line Distance Protection

(iv) Over Current & Earth Fault Protection

(v) Over/Under Voltage Protection

(vi) Breaker Failure Protection

(vii) Transfer Trip Protection Schemes

(viii) Over/Under Frequency Protection

(ix) Auto Recloser with built-in Synchronism Check feature

(x) Bus Coupler Protection

(xi) Line Open Circuit Fault (Broken Conductor) Protection

(xii) Backup Over Current & Earth fault Protection on 132 kV Transmission Lines

(xiii) Provision for Implementation of Cross-Trip/Special Protection Scheme

(h) Interconnectors (DC Protections)

(i) Converter Protection

a. Voltage Stress Protection

b. Valve Short-circuit Protection

c. Commutation Failure Protection

d. Backup Terminal DC Voltage Supervision Protection

e. DC Overcurrent Protection

f. Valve Misfire Protection

(ii) Pole Protection

a. DC Differential Protection

b. DC Line Ground Fault Protection

c. DC Harmonic Protection

d. DC Abnormal Voltage Protection

e. DC Filter Overload Protection

f. Electrode Line Open-circuit Protection

(iii) DC Switchyard Protection

a. Bipole Neutral Differential Protection

b. Metallic Return Conductor Ground Fault Protection

c. Transfer Breaker Protection

d. Station Ground Over-Current Protection

e. Electrode Cable Longitudinal Differential Protection

f. Electrode Line Unbalance Supervision

g. Electrode Line Impedance Supervision

(iv) DC Line Protection

a. Travelling Wave Front Protection

b. Under Voltage Sensing Protection

c. Under Voltage Operation Protection

d. DC Line Differential Protection

e. Remote Station Fault Detection or AC-DC Conductor Contact Protection

f. Electrode Line Protection

(v) DC Filter Bank Protection

a. Capacitor Differential Overcurrent Protection

b. Capacitor Unbalance Supervision

c. Inverse Overcurrent Time Protection

d. DC Filter Differential Protection

(vi) Miscellaneous DC Protection

e. Bridge Differential Protection

f. Sub-Synchronous Resonance Protection

g. Open Converter or DC Overvoltage Protection

h. Excessive Delay Angle Protection

(i) Interconnectors (AC) Protections

(i) AC Bus and Converter Transformer Protections

a. Differential Protection

b. Over-current & Earth fault Protection

c. AC Bus Over-Voltage Protection

d. Thermal Overload Protection

e. Transformer Winding Differential Protection

f. Transformer Zero Sequence Current Protection

g. Transformer Neutral Shift Protection

h. Transformer Over-excitation Protection

i. Transformer Saturation Protection

j. Transformer Restricted Earth Fault Protection

(ii) Last Breaker Protection AC Filter/Shunt Bank Protections

a. Differential and Over-current Protection

b. Filter Over-voltage Protection

c. Capacitor Unbalance Protection

d. Zero Sequence Current Protection

e. Filter Detuning Supervision

f. Resistor/Reactor Harmonic Overload Protection

g. Low Voltage Capacitor Protection

h. Start Breaker Failure Protection

PCC 2.3. **Instrument (Current and Potential) Transformers**

PCC 2.3.1. Current Transformers (CTs) and Potential Transformers (PTs) shall be furnished for the Protection Systems that shall meet with the standards and specifications of the NGC.

PCC 2.3.2. CTs and PTs shall have the accuracy, ratio and burden ratings required to operate the protective relays.

PCC 2.3.3. Instrument transformer used for protective relaying shall not be shared with any revenue Metering equipment. Likewise, instrument transformers for revenue Metering shall not be shared with protective relaying equipment.

PCC 2.4. **Shunt Reactor Protection**

PCC 2.4.1. The use of circuit breaker for the shunt reactor shall be mandatory for all Users.

PCC 2.4.2. In special cases, only if allowed by the SO to temporarily install shunt reactors without circuit breakers, then protective relaying on shunt reactors shall be used to trip associated line circuit breakers. Isolation-switches shall be provided to allow the isolation of shunt reactors and circuit breakers for maintenance.

PCC 2.5. **DC Supply of User's Substation/switchyard**

PCC 2.5.1. DC Back-up power supply shall be provided in the User's substation/switchyard. The User substation/switchyard shall be equipped with independent two (2) No. DC battery banks to provide independently protected and monitored DC sources for reliable Protection System(s).

PCC 2.5.2. Independent DC Back-up power supply shall also be provided in the User's substation/switchyard for communication equipment including PLCC, OPGW, etc.

PCC 2.5.3. Two separate floating cum boost battery charging facilities shall be available for each DC voltage level. One should always be in service while the other shall be in hot standby mode through DC distribution box (DB) and should immediately respond in case of failure of primary supply.

PCC 2.5.4. Users shall ensure testing and periodic checks to verify the readiness and adequacy of DC systems and facilities in their substations/switchyards, i.e., battery, charger, and distribution switchboard including DC system supervision relay. Testing/checking shall be carried out as per NGC practices/guidelines.

PCC 2.6. **Switching Procedures**

PCC 2.6.1. All switching activities at the Connection Point shall be performed under the direction of the SO. All other switching activities in the User's system shall be coordinated with the SO. Proper communication and tagging procedure shall be observed to prevent accidents and damage to equipment involved in the switching operation.

PCC 2.6.2. The details regarding switching procedures shall be as per OC.

PCC 3. **GENERATING UNIT PROTECTION**

PCC 3.1. Connection between a Generating Unit and the Transmission System must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the Connection Point. The maximum short circuit current shall be specified by the SO after Grid Impact Studies.

PCC 3.2. **Protection Design**

The Generating Unit shall include protections, not limited to the following:

(a) Protection System shall be designed to provide adequate protection of the Generating Unit and its substation/switchyard Apparatus.

(b) Differential protection (Main-I and Main-II) on the Generator Transformer. The connections between the Connection Point's circuit breaker and the HV terminals of the Generator Transformer shall be included in the protected zone of this differential protection.

(c) Short-circuit and earth fault protection of primary conductors from the current transformer at the line side of the circuit breaker to the Connection Point shall be provided.

(d) Circuit breaker fail protection shall be provided at the Generating Unit. A Back-up trip signal shall be provided in the event of a main circuit breaker failure to trip all the electrically adjacent breakers to clear the fault <u>within the time limits provided under the NGC standards.</u>

(e) Protection shall be provided to initiate a Generating Unit trip when loss of excitation is detected.

(f) Pole slipping protection shall be provided with the synchronous generating units.

(g) The Protection System of Generating Unit shall ensure that fault in Generating Unit facility must be cleared by its Protection System and there will be no adverse effect on the Transmission System.

PCC 3.3. **Requirements at the Connection Point**

Protection of Generating Units and their connections to the Transmission System must meet the minimum requirements (relay settings are to be reviewed by NGC from time to time) which includes but not limited to the following:

(a) For faults on the Generating unit's equipment directly connected to the Transmission System and for faults on the Transmission System directly connected to the Generating unit's equipment, fault clearance period from fault inception to circuit breaker arc extinction shall be as per SO requirements.

(b) In the event where the fault clearance times are not met as a result of failure to operate the primary or main protection system, a Back-up or secondary protection system shall operate. Back-up protection along with the specified fault clearance time shall be coordinated with the Users so as to provide adequate discrimination.

(c) On the Generating Unit connected to the Transmission System where primary or main protection is provided to clear fault on the high voltage Generating Unit connections within the required fault clearance time, the secondary or Back-up protection in the Generating Unit, shall operate to give a total fault clearance within the limits as per SO requirements.

(d) Generating Unit's secondary or Back-up protection relays shall be required to withstand, without tripping, the loading incurred during clearance of a fault by a breaker fail protection on the Transmission System. Back-up protections in the Generating Unit and Transmission System shall be coordinated to provide adequate discrimination.

(e) Circuit breakers installed at the Connection Point between the Generating Unit and the Transmission System shall be provided with breaker failure protection. In the event the breaker fails to operate, the breaker failure protection shall initiate tripping of all the electrically adjacent circuit breakers within the time limits provided by NGC as per SO requirements.

(f) The target performance for the System Fault Dependability Index shall not be less than 99%. This is a measure of the ability of the Protection System to initiate successful tripping of circuit breakers that are associated with the fault in the system.

(g) NGC shall review and approve schemes/settings necessary to protect the Transmission System, taking into account the characteristics of the Generating Units and system stability. The protection schemes/settings needed for the Generating Units and the Transmission System shall be coordinated among the NGC, TNO and the Generator. The Protection Schemes and their settings shall not jeopardize the performance of a Generating Unit or the Transmission System.

(h) Electrical protection of the Generating Units shall take precedence over operational controls, taking into account the security of the System and the health and safety of staff and of the public, as well as mitigating any damage to the Generating Units.

PCC 3.4. **Requirements for Rate of Change of Frequency (ROCOF)**

The operation of the ROCOF relay may be based either only on the rate of change (rise/fall) of frequency (± df/dt) or both on a set frequency value and the rate of frequency recovery/decline [(f> and +df/dt) OR (f< and -df/dt)]. ROCOF detection shall not be instantaneous, rather it shall be calculated over 500 milliseconds span after frequency is filtered properly i.e., sample shall be taken every 5 milliseconds and calculated over 500 milliseconds span for operation of ROCOF relay. It is further added that at any ROCOF whether ramping up or down between range of 48.5 Hz to 51 Hz, the relay shall not activate and the Generating Unit itself shall remain stable at any ROCOF between this frequency range. Recommended settings based on generator/Interconnector capability are as under:

PCC 3.4.1. For Gas Turbine Generators:

(a) Rate of Change of Frequency (ROCOF) setting based on generator capability in case frequency ramping up i.e., $f > 51.0$ Hz and $+df/dt \geq 1.5$ Hz/Sec with time delay of 500 milliseconds (minimum).

(b) Rate of Change of Frequency (ROCOF) setting based on generator capability in case frequency ramping down i.e., $f < 48.5$ Hz and $-df/dt \geq 1.5$ Hz/second with time delay of 500 milliseconds (minimum).

PCC 3.4.2. For Steam Turbine Generators (e.g., coal, natural gas, biomass, nuclear), Wind Farms, Hydro-electric Turbine Generators etc.:

(a) Rate of Change of Frequency (ROCOF) setting based on generator capability in case frequency ramping up i.e., $f > 51.0$ Hz and $+df/dt \geq 2.0$ Hz/Sec with time delay of 500 milliseconds (minimum).

(b) Rate of Change of Frequency (ROCOF) setting based on generator capability in case frequency ramping down i.e., $f < 48.5$ Hz and $-df/dt \geq 2.0$ Hz/Sec with time delay of 500 milliseconds (minimum).

PCC 3.4.3. For the HVDC, the capability to remain connected to the Grid and being operable if the network frequency changes at a rate between – 2.5 and + 2.5 Hz/s (measured in the AC part of the Converter Stations as an average of the rate of change of frequency for the previous one (1) second).

PCC 4. USERS SUBSTATION/SWITCHYARD PROTECTION FOR CONNECTION WITH TRANSMISSION SYSTEM

PCC 4.1. Users' substations/switchyards for Connections with the Transmission System must meet the minimum requirements delineated below:

PCC 4.1.1. For faults on the User's substation/switchyard equipment directly connected to the Transmission System and for faults on the Transmission System directly connected to the User's substation/switchyard equipment, fault clearance period from fault inception to circuit breaker arc extinction shall be as per SO requirements. The period specified shall meet the requirements of transient stability based on SO experience and NGC guidelines/practices.

PCC 4.1.2. Longer fault clearing times may be specified by SO keeping in view protection and design criteria of the TNO.

PCC 4.1.3. Where the fault clearance times are not met as a result of failure to operate the primary or main protection system, a Back-up or secondary protection system shall operate. Back-up protection shall be coordinated with the primary protection so as to provide adequate discrimination.

PCC 4.1.4. Users' substations/switchyards connected to the Transmission System where primary or main protection is provided to clear faults on the Connection Point within the required fault clearance times, the secondary or Back-up protection shall operate to give a total fault clearance within the limits as per SO requirements.

PCC 4.1.5. Users' substation/switchyard secondary or Back-up protection relays will be required to withstand, without tripping, the loading incurred during clearance of a fault by a breaker fail protection on the Transmission System. Back-up protections in the substation/switchyard and Transmission System shall be coordinated to provide adequate discrimination.

PCC 4.1.6. Circuit breakers installed at the Connection Point between the User's substation/ switchyard and the Transmission System shall be provided with breaker fail protection. In the event the breaker fails to operate at User's substation/switchyard, the breaker-fail protection will initiate tripping of all the electrically adjacent circuit breakers within the time limits provided by NGC as per SO requirements.

PCC 4.1.7. The target performance for the system Fault Dependability Index shall not be less than 99%. This is a measure of the ability of the Protection System to initiate successful tripping of circuit breakers that are associated with the fault on the System.

PCC 4.1.8. The Back-up protection relays of the User's system also need to be coordinated with the Back-up protection of the other User facility (as the case may be) and the Transmission System. The coordination times specified by NGC shall be followed by all Users.

PCC 4.1.9. For facilities Interconnection between new User and existing User, if any addition/change/modification in Protection & Control equipment/devices is required at existing User's grid station(s) to complete the scheme, the same shall be procured, installed, commissioned & tested by the new User at existing User grid station(s) at his own cost & expense. The operation & maintenance (O&M) of such Protection and Control equipment/devices along-with all other allied material, installed at existing User Grid Station(s) shall be the responsibility of existing User. However, if the equipment/technology is new and require training for O&M, the same shall be arranged by the new User at his own expenses. Further, the User shall also transfer this asset to the existing User with ownership & warranty claims etc.

PCC 5. PROTECTION COORDINATION

PCC 5.1. General

PCC 5.1.1. Users' Plant and Apparatus shall be protected from faults and overloads at the Connection Point. Both primary and secondary (Back-up) protection schemes are to be provided to enhance System Reliability.

PCC 5.1.2. The User must submit proposed relay settings of their facilities for the review and approval of NGC. If requested, the relevant TNO shall provide Transmission System data to the User needed to calculate the relay settings.

PCC 5.1.3. Protection settings of Users shall be coordinated with the transmission line and substation/switchyard protection to prevent inadvertent and unwanted operations.

PCC 5.1.4. Design and settings of Protection System shall be coordinated among the Users. Settings of protective devices shall be reviewed periodically to maintain consistency with operation, planning and protection design standards.

PCC 5.1.5. All protection, control, monitoring & recording equipment/devices/systems shall be in accordance with relevant specifications of NGC and Prudent International practices.

PCC 5.2. **Fault Clearance Times**

PCC 5.2.1. Faults on Users' Plant and Apparatus connected to the Transmission System shall comply with the following requirements for Fault Clearance Times (from fault inception to Circuit Breaker's arc extension) by primary Protection not exceeding :

(a) 120 milliseconds for the 132 kV system and below

(b) 100 milliseconds for the 220 kV system

(c) 80 milliseconds for the 500 kV system and above

PCC 5.2.2. The maximum allowed times for fault clearance specified in PCC 5.2.1 shall be considered as reference, unless some other clearance times are required by SO.

PCC 5.2.3. The clearance times specified in PCC 5.2.1 are for primary Protection Systems only. Without limiting this obligation, prior to connection with the Transmission System, a User shall as a minimum, install and maintain the protection equipment as per requirements of SO and relevant TNO in accordance with Good Industry Practice.

PCC 5.2.4. For the avoidance of doubt, the User is solely responsible to determine the adequacy of protection equipment installed by the User for protecting its Plant and Apparatus against Transmission System disturbances. NGC standards and specifications to meet SO requirements are primarily intended to protect the Transmission System and its associated facilities to ensure System Stability and Reliability, and although these may afford a level of protection to Users, these are not primarily designed to protect User's facilities.

PCC 5.3. **Relay Coordination**

PCC 5.3.1. Protective relays in the various sub-systems of the Transmission System must be coordinated to prevent unwanted tripping. Proper coordination of Protection Systems of the various sub-systems will enhance the security and safe operation of the system.

PCC 5.3.2. Relay coordination shall be checked and updated each time the system characteristics are substantially changed/modified, but in any case, at least after every five (5) years by the NGC, using state-of-the-art relay-coordination software.

PCC 5.3.3. NGC/SO should maintain the transmission system protection database, tripping database, relay and protection performance database and shall be share with relevant participants in case of requirement this database should be shared with all participants to ensure proper data exchange for coordination activity.

PCC 5.3.4. Users shall exchange primary and Back-up relay setting times and other necessary parameters to facilitate the co-ordination of the interfaces between Users' facility; and shall fully co-operate with the NGC/TNO to implement settings/schemes for their respective Protection and Control equipment to meet SO requirements.

PCC 5.3.5. Prior to energization of a User's Facility, the User shall submit the relay settings to NGC for review and approval, which the User proposes to apply to its Facility's Protection and Control equipment. If requested, the User shall provide data/parameters of its Facility/system to other Users, required for calculation and coordination of the relay settings.

PCC 5.3.6. The NGC shall, within the specified time of receiving the User's submission of relay settings, notify to the User that it approves the proposed settings; or if NGC determines that the settings proposed by the User are not in accordance with the applicable standards/requirements, disapproves these settings along with comments/recommendations to be incorporated. The User, after addressing the NGC's concerns, shall submit the revised settings to the NGC.

PCC 5.3.7. If any change or modification is envisaged by the Users in relay settings/protection schemes prior to energization of the User's facility due to any untoward situation, the Users shall notify to the SO without delay along with intimation to NGC. Such change/modification shall be implemented by the Users after approval of NGC.

PCC 5.3.8. If any change/modification is required, the User requesting Connection with the Transmission System, shall be liable to revise the relay settings of already connected User(s) which got affected by this User's facility, in consultation/approval of NGC. Any cost incurred shall be borne by the User requesting the change, in such cases.

PCC 5.3.9. Protection coordination studies including Cross-Trip schemes, Remedial Action Schemes, etc., shall be performed after every three (3) years by engaging independent consultant(s), based on which Stability, Security and Reliability of the National Grid shall be evaluated and validated jointly by SO and NGC.

PCC 5.3.10. NGC/SO should maintain the transmission system protection database, tripping database, relay and protection performance database and should be shared with relevant participants. In case of requirement this database should be shared with all participants to ensure proper data exchange for coordination activity.

PCC 5.4. **Tripping & Reclosing Schemes**

PCC 5.4.1. The equipment and allied schemes for the 220 kV, 500 kV and higher voltage levels shall be capable of both single pole and three pole tripping & reclosing arrangement. The configuration of the tripping scheme shall be finalized jointly by SO, TNO and NGC which will be adopted by each User.

PCC 5.4.2. The line relaying system shall be arranged to allow for Single Pole Tripping of selected 220 kV, 500 kV and higher voltage transmission lines, in case of single phase to earth fault. One-shot re-closing of the tripped line shall be allowed according to studies designed to establish the best re-closing time. If the tripped phase fails to re-close, all three phases will be tripped accordingly.

PCC 5.4.3. Three pole tripping shall also be associated with delayed Auto-Recloser scheme with successful synchronism-check feature. The reclosing scheme, relevant time-delay and allied parameters shall be as per NGC standards.

PCC 6. **CONTROL & AUTOMATION**

PCC 6.1. **General**

PCC 6.1.1. The control & automation shall be as per the requirements laid down in the NGC approved standards/specifications. All the technical data including device and equipment ratings shall be submitted by the User to NGC/TNO for its review and approval.

PCC 6.1.2. For the purpose of Connection and Disconnection of Generator and User's substation/switchyard to/from the Transmission System, the necessary equipment shall be provided which includes but not limited to the following:

PCC 6.1.2.1. Circuit breakers shall be provided at the Connection Point between the Users and the Transmission System. The circuit breaker shall have the proper voltage ratings, short circuit current rating, continuous current rating, etc.

PCC 6.1.2.2. Control panels for circuit breakers, disconnecting switches and other equipment (wherever applicable) shall be provided at the Connection Point.

PCC 6.1.2.3. Disconnecting switches shall be provided for isolation of circuit breaker. Disconnecting switches shall be no-load break type and have the same voltage and continuous current rating as of the circuit breaker.

PCC 6.1.2.4. Disconnecting switches shall be provided for isolation of transformer in the substation/switchyard. Disconnecting switches shall have wipers to prevent arcing during energization of the transformer. Disconnecting switches shall be of no-load break type and shall have the same voltage and continuous current as of the circuit breaker.

PCC 6.1.2.5. Disconnecting switches shall be provided for the bus bars for safety and maintenance purpose. The grounding feature may be provided as per NGC standards and specifications.

PCC 6.1.2.6. Disconnecting switches with grounding feature shall be provided for the Transmission lines for safety and maintenance purpose.

PCC 6.1.2.7. Disconnecting and Earthing switches shall be motor-operated to facilitate remote operation. Control and electrical interlocks for Disconnecting and Earthing switches shall be provided in the control panel that shall have interface with SCADA for remote control and monitoring.

PCC 6.2. **SCADA**

PCC 6.2.1. Users shall install and integrate SCADA system of their network/ facilities with SO’s designated control centers and shall be fully compatible with the SO’s SCADA system. The telecommunication system shall be fully compatible with the SO/TNO communication system.

PCC 6.2.2. The telecommunication equipment for remote SCADA interface (e.g., RTUs, gateways etc.) used for Substation Automation System (SAS) shall comply with the NGC standards and specifications to meet SO requirements.

PCC 6.2.3. In case substation/switchyard or generating station has implemented Parallel Redundancy Protocol (PRP) based Substation Control/Automation, the equipment, Apparatus, and all accessories shall comply with the NGC standards and specifications to meet SO requirements.

PCC 6.2.3.1. SCADA connections for monitoring and control of circuit breakers, disconnecting switches, Earthing switches and other protection devices shall be provided for SO's designated control centers.

PCC 6.2.4. The detailed requirement of communication facilities to be provided by Users shall be covered in the Connection Code, Operating Code, and respective Agreement(s) with a specific User.

PCC 6.3. **Time Clock Synchronization**

PCC 6.3.1. Time clock in protection devices, recording equipment and SCADA shall have facilities for synchronizing time with Global Positioning System (GPS). The User shall provide at the Connection Point the required signal receiving and signal distribution equipment.

PCC 6.3.2. Time clock synchronization source for the Protection, event recording, fault recording and SCADA applications shall be Precision Time Protocol (PTP) compliant and shall be in-line with the requirements laid down in the NGC standards and specifications to meet SO requirements.

PCC 6.4. **Fault & Event Recording Requirements**

PCC 6.4.1. Equipment for recording fault conditions and sequence of events shall be provided by the User at the Connection Point. The recording equipment shall record a snapshot of the voltages and current during the fault, and sequence of events for subsequent investigation and evaluation of the fault to determine its cause(s). The fault recording equipment shall have facilities for the information provision via SCADA to SO's designated control centers.

PCC 6.4.2. Fault recording equipment design shall at least be as per the NGC standards and specifications and shall have the facility for online-transfer of data to the respective user. It shall be an independent/standalone equipment for Substation/Switchyard.

PCC 7. **INSPECTION AND TESTING**

PCC 7.1. **General**

PCC 7.1.1. The inspection and testing including site acceptance tests (SAT) of the User Facility shall follow the procedures as mentioned in CC13.

PCC 7.1.2. The facility shall be witnessed and inspected jointly by SO, NGC and TNO. The User shall be responsible for providing necessary equipment with valid calibration certificate and qualified personnel, who will complete all the required/ necessary tests.

PCC 7.1.3. User shall be liable for arranging type tests, Factory Acceptance Tests (FAT) and SAT, where applicable, for all protection equipment of its Plant and Apparatus, to be witnessed by authorized representatives of the NGC and TNO. Test results shall demonstrate the design performance, functionality, and safety of individual protection equipment as well as the entire User system, up to the satisfaction of NGC and TNO.

PCC 7.1.4. The User shall pre-commission and on successful pre-commissioning user must notify the SO, NGC and TNO prior to performing the required tests for final commissioning. Approved drawings must be provided to the SO, NGC and TNO at least seven (7) business days before performing the testing.

PCC 7.1.5. Once SO, NGC and TNO determines that the installations are suitable to operate in connection with the Transmission System, the User, SO, NGC and TNO representatives (whichever applicable) must sign and date the "Approval for operation of the facility" certificate. After receiving the “Approval for operation of the facility" certificate, the User will be authorized to operate its facility in parallel with the Transmission System.

PCC 7.1.6. User shall provide the final version of updated drawings (As-Built) in all aspects in an agreed format to the SO, NGC and TNO for the record.

PCC 7.2. **Periodic Testing, Calibration and Maintenance of Protection Systems**

PCC 7.2.1. Periodic testing of all Protection Systems including relays, control and switching equipment and allied system shall be carried out by the relevant User to ensure that entire Protection System is in good operating condition. Protection devices found defective during the test must be repaired or replaced, accordingly. Circuit breakers and control circuits shall also be tested periodically, and if parts are found defective or deficient, they should be repaired or replaced. Testing and maintenance shall be coordinated among the User, SO, NGC and TNO (whichever applicable). Tests, calibration, repair and replacement of equipment shall be recorded and disseminated to all concerned parties.

PCC 7.2.2. Users shall perform testing of their protective relay under supervision of the NGC, or may request NGC to perform testing of their relays after payment of service charges.

PCC 7.2.3. Users shall perform routine testing of their protective relay and submit the test report to NGC as per the prescribed format under testing procedure developed by NGC.”

PCC 7.2.4. All testing and maintenance performed on the Protection and Control equipment of the User shall be recorded, and copies submitted to SO, NGC and TNO for record and archiving. The User shall keep records for a period of at least ten (10) years.

PCC 7.2.5. User shall carry out a thorough periodical review, testing, calibration and maintenance of its entire Protection System at the Connection Point as well as for its complete network/facility.

PCC 7.2.6. User(s) shall provide annual testing schedule of their Protection Systems in its/their substation/switchyard. The TNO, SO and NGC shall have the right to require additional testing as well as the recalibration of the testing equipment. User shall arrange such testing equipment so as to meet the quality standards of NGC for performing these tests.

PCC 7.2.7. User shall ensure verification of the protection settings/schemes at the Connection Point along with healthiness of associated Protection System, to be witnessed by the NGC and TNO on annual basis.

PCC 7.3. **Right to Inspect**

The SO shall have the right to inspect (as and when required) substation(s)/switchyard(s) and transmission lines that are connected to the Transmission System. The NGC and relevant TNO (as and when required) shall also have the same right to inspect the transmission lines/generating stations/substations connected to their systems at the Connection Point.

METERING CODE

MC 1. INTRODUCTION

Metering Code sets out the rights, responsibilities and obligations of entities with respect to:

(a) measurement and recording of electricity quantities i.e. energy and power;

(b) provision, installation, commissioning, maintenance, repair, replacement, inspection, testing and audit of revenue Metering Systems; and

(c) provision, verification, communication, security and accuracy of Metering Data for purposes of billing and settlement.

Following conditions governing metering equipment and Metering Data are specified in this Metering Code:

(a) technical, design and operational criteria

(b) accuracy and error limits

(c) testing and approval of metering equipment

(d) meter reading and data management including Validation, Estimation, and Editing (VEE) rules application

(e) Secured Metering System (SMS) / Advanced Metering Infrastructure (AMI) requirements

MC 2. SCOPE

This Code applies to Meter Service Provider (MSP) and the following Users:

(a) Transmission Network Operators (TNOs);

- (i) National Grid Company (NGC, currently this is called NTDC)
- (ii) Provincial/Regional Grid Companies (PGCs/RGCs)
- (iii) Special Purpose Transmission License Companies (SPTLs)
- (iv) Distribution Companies (DISCOs)

(b) Generators connected to the Transmission System;

(c) Bulk Power Consumers connected to the Transmission System; and

(d) Interconnectors.

MC 3. METERING SYSTEM

MC 3.1. A Metering System shall consist of the following equipment at Connection Points between the Transmission System and the User system for revenue metering:

(a) Energy meters along with meter communication devices;

(b) Instrument transformers; Current Transformer (CT) and Voltage Transformer (VT)

(c) Secondary circuits of Instrument Transformers including interconnecting cables; wires, metering cabinets and associated devices.

MC 3.2. All above equipment must conform to the criteria and standards as set forth under section MC 4 in this Metering Code.

MC 3.3. **Configuration**

Metering system for revenue metering shall have the following configuration:

(a) Primary Metering System comprising of primary energy meters (along with communication devices), dedicated separate sets of Instrument Transformers (CT and VT) and their secondary circuit equipment for metering purposes. In case of BPCs up to 30MW, the configuration of instrument transformers (CT and VT) may be considered as mentioned in MC 4.3.2.

(b) Backup Metering System comprising of backup energy meters (along with communication devices), Instrument Transformers (CT and VT) and their secondary circuit equipment to be used for backup metering purposes.

MC 3.4. **Provision**

MC 3.4.1. MSP or User shall provide the Primary and Backup Meters along with the associated communication equipment, at Users cost. User shall install the same and offer them for commissioning by MSP.

MC 3.4.2. MSP shall be responsible for the operation and maintenance of the Primary and Backup Meters (along with meter communication equipment).

MC 3.4.3. The User that owns the connection facility shall provide, install, and commission Primary and Backup Instrument Transformers (CT and VT) and all their allied secondary circuit equipment.

MC 3.4.4. After commissioning, User shall be responsible for the operation and maintenance of Primary and Backup Instrument Transformers (CT and VT) and all their allied secondary circuit (excluding the meters and meter communication equipment). Any such O&M activity shall be carried out by User under supervision of MSP and subject to MC 4.7.4.

MC 3.4.5. The User shall submit to MSP for approval of the following as per the relevant technical data schedules attached as annexure to this Metering Code:

(a) engineering design for revenue metering

(b) the detailed data for all components of Metering System

(c) proposed location of metering equipment and ancillaries complete with wiring and installation drawings and design

MC 3.5. **Location**

MC 3.5.1. **Metering Point**

MC 3.5.1.1. Metering Point shall be at the physical location of the Connection Point with the following arrangements:

(a) At generation facilities, the Metering Point shall be at high-voltage side of generator step-up transformer.

(b) At load facilities, the Metering Point shall be at low-voltage side of the step-down transformer.

MC 3.5.1.2. Notwithstanding the above, the cost of transformation and transmission lines losses shall always be with the User that owns, operates, and maintains the asset.

MC 3.5.2. **Site-specific Loss Compensation**

MC 3.5.2.1. In case of practical constraints and exceptional circumstances, Metering System could be installed at a location different from the Metering Point. MSP shall determine the parameters required to account for losses/adjustment (if any) in case the Metering System is installed at a location other than the Metering Point.

MC 3.5.2.2. Such deviations shall be agreed among the relevant Users and MSP before execution of Connection Point, recorded in an appropriate manner by the MSP and communicated to System Operator for Record, and Market Operator for the purpose of billing and settlement. If required, the relevant Users may approach NEPRA for any regulatory tariff adjustment. Any such scenario cannot be claimed as reference.

MC 3.6. **Metering Point Documentation**

MSP shall maintain documentation containing the following minimum information regarding each Metering System:

(a) unique identification and name of the Metering Point and User site;

(b) unique identification and name of the relevant User;

(c) a metering single line drawing showing the actual electrical location of all the meters and Instrument Transformers within the Metering System;

(d) the unit of measurement used to measure energy and power flowing through the Metering System;

(e) the unique internal meter identifier, the passwords, the online secure communication address for the Metering System;

(f) the site-specific loss adjustment and measurement error correction factors to be applied, including the sign of the loss adjustment;

(g) the burdens connected to each Instrument Transformer contained within the metering system;

(h) the Instrument Transformer detailed data and operational configuration;

(i) the contact details for purpose of communication between the MSP and the relevant User; and

(j) any other integration remarks, as deemed appropriate by the MSP.

MC 4. **METERING SYSTEM PERFORMANCE REQUIREMENTS**

MC 4.1. **Applicable Standards**

The components of Metering Systems must comply with the latest applicable standards (international and national) including but not limited to the following:

(a) IEC 62052 and IEC 62053– static meters for active and reactive energy

(b) IEC 61869Instrument Transformers - General and additional requirements.

(c) IEC 61107 – Standard for electricity Metering Data exchange

(d) IEC 62056 – Standards for electricity Metering Data exchange (DLMS, COSEM)

(e) NGC specifications for Metering System

MC 4.2. **Energy Meters**

MC 4.2.1. In addition to compliance with the relevant standards as mentioned in MC 4.1, the Primary and Backup Meters shall have the following minimum characteristics:

(a) Bidirectional, 4-Quadrant electronic, digital, with 3-Phase 4-wire meter connection configuration with accuracy class as defined in MC 4.6.

(b) Meter shall be rated for

(i) Reference voltage (phase-phase) = 100-110V

(ii) Reference frequency = 50Hz

(iii) 1.2In A current with selectable option for 1A or 5A

(iv) Short-time over-current shall be 20 times Imax for 0.5s

(v) Impulse voltage withstand level = 8kV

(vi) Power frequency withstand level = 4kV

(c) Meters shall be capable of measuring and recording time stamped Load Profile. The Load Profile must support multiple channels (minimum 16 channels) with configurable logging interval and the minimum memory capacity as follows:

(i) incremental or cumulative energy (active & reactive) @ 30 mins interval for 70 days

(ii) instantaneous values @ 5 mints interval for period of 10 days;

(iii) last interval average values @ 30 mints interval for a period of 70 days

(d) The meter must have the capability of recording active and reactive power, and energy for defined billing period. The meter-billing period may be programmable and shall automatically store the accumulated registers and increment the reset counter for the next billing period.

(e) Meter shall store all Energy and MDI registers for at least 15 previous billing intervals.

(f) Multiplier corresponding to the combination of CT and VT ratios may be programmable in the meter and any manual meter multiplying factor shall be avoided.

(g) Meters shall have internal time clock for time and date stamping of Metering Data. Time clock must be capable of synchronization to Meter Data Management (MDM) server that will be according to the Pakistan Standard Time.

(h) Meters shall support Maximum Demand measurement over programmable fixed intervals.

(i) Meters should have capability for remote meter reading by Advanced Metering Infrastructure (AMI) and/or by SCADA and communication/integration with the central Meter Data Management (MDM) Server of MSP. Data communication ports as per requirement of MSP shall be provided along with optical communication.

(j) Meter should have self-diagnostic capability, maintain complete event log; and include an alarm to indicate failure and/or tampering.

(k) Primary and Backup Meters shall be subject to all the type and special tests as required in relevant IEC standards. Further, the meter shall be factory calibrated and shall be suitably sealed before dispatch.

MC 4.3. **Instrument Transformers**

MC 4.3.1. In addition to compliance with the relevant standards as mentioned in MC 4.1, the Primary and Backup Instrument Transformers shall have the following minimum characteristics:

(a) The primary dedicated metering CT, VT and cables connected to Primary Meters shall be dedicated for metering purposes only and shall not be shared with any other system.

(b) The backup dedicated metering CT, VT and cables connected to Backup Meters shall be dedicated for metering purposes.

MC 4.3.2. In case of BPCs up to 30MW only, Primary Metering System may utilize separate metering cores of available instrument transformers (CT and VT) for metering in addition to protection purposes after due approval of MSP as mentioned in MC 3.4.5.

MC 4.3.3. In case dedicated backup metering CT, VT are not available, the Backup Meters, with the approval of MSP, maybe connected with the separate metering core of available CT, VT.

(a) CTs and VTs shall be operated within the rated burden limits. Any change/modification in the connected burden of CTs and VTs shall only be with the approval of MSP.

(b) Dedicated metering CTs and VTs shall have a locking termination compartment that can be sealed. All wiring between the CTs and VTs shall be stranded copper wire, with PVC/polyethylene jacket.

(c) The Primary and Backup current transformers shall have a rated secondary current of 1A, and burden of minimum 10VA.

(d) Primary and Backup Metering Instrument Transformers shall be subject to all the type and special tests as required in relevant IEC standards.

(e) The short circuit withstand level for Instrument Transformers shall be in compliance with the system studies approved by the respective TNO.

(f) Primary and Backup Metering Instrument Transformers shall be subject to all the type and special tests as required in relevant IEC standards.

MC 4.3.4. Where the existing Instrument Transformers do not comply with the conditions of this Metering Code, those shall be replaced with the fully compliant Instrument Transformers with a mutually agreed timeline between the MSP and the User.

MC 4.4. Secondary Circuits of Instrument Transformers

MC 4.4.1. The secondary circuits of Instrument Transformers shall include interconnecting cables, wires, metering cabinets and associated devices like test blocks, VT fuses/VT MCBs (Miniature Circuit Breakers), contactors etc. and shall conform to the following minimum requirements:

(a) terminals shall be provided for Primary and Backup Meters to facilitate on site tests. These terminals shall be in close proximity to the Meters.

(b) metering cabinets for Primary and Backup Metering Systems shall be separately installed in the switchyard near the Metering Point in separate metering room.

(c) the Primary Meter, Backup Meter and additional burdens (if any) shall have separately fused VT supplies.

(d) the metering cabinet shall be heavy gauge steel, primed and finished with grey finish, with locking door. A glass window shall be provided on the door to permit visual and optical port reading of the meter.

MC 4.5. Meter Communication Devices (Modules/Modems)

MC 4.5.1. Separate communication modems for Primary & Backup Meters shall be made available to ensure online availability and redundancy of Metering Data via appropriate channel e.g. GSM/4G/VSAT/OPGW/SCADA/PLC to Meter Data Management (MDM) Server of MSP and then onwards communication to the Market Operator and to SO (if required).

MC 4.5.2. The communication between the Meters and MDM Server of MSP shall be isolated from other network communications to ensure network security.

MC 4.5.3. The associated communication modules and routers used for online communication of meters with MDM Server of MSP shall also be network hardened and secured.

MC 4.6. Selection of Accuracy Class and Error Limits

Metering System accuracy class selection shall be as per Table MC-1.

Table MC-1: Meters and Instruments Accuracy Class

Equipment		**Equipment Accuracy Class Selection**
Current Transformers		0.2s
Voltage Transformers		0.2
Meters	Active Energy	0.2s
	Reactive Energy	0.5s

Error limits in accuracy for measurement of active & reactive energy of energy meter and Instrument Transformers shall be as per relevant IEC standards.

MC 4.7. **Security and Sealing**

MC 4.7.1. All components of Metering Systems (energy meters, meter communication devices, instrument transformers and their secondary circuits) shall be installed in such a manner that they cannot be tampered with.

MC 4.7.2. The MSP shall make arrangement to seal and secure all Primary & Backup Metering Systems with unique serial number seals.

MC 4.7.3. All wiring between Instrument Transformers outside the metering compartment shall be installed in rigid galvanized steel conduits.

MC 4.7.4. The authorized representatives of the relevant User and MSP shall be present while sealing / de-sealing of the Metering System. The record for all such sealing/de-sealing activities shall be maintained by MSP.

MC 4.7.5. The room housing Primary Meters and Backup Meters shall be locked and sealed under supervision and control of authorized representative of MSP.

MC 4.7.6. To prevent unauthorized access to the data in the meters a security scheme, as described below, shall be incorporated for both direct local and remote electronic access. Separate security levels shall be provided on meters for the following activities:

(a) Meter time, data registers and Load Profile read shall be without password.

(b) Level 1 – password for programming of CT and VT ratios, and other parameters including Load Profile configuration, display sequences, MDI demand Period, MDI reset.

(c) Level 2 – password for corrections to the time and date

MC 4.7.7. To prevent unauthorized access to the Metering Data and the communications of Metering Systems, VPN (Virtual Private Network) / Firewall security shall be implemented by MSP.

MC 4.7.8. If MSP finds out that a User's Metering System has been apparently tampered, a complete audit of User's Metering System shall be performed by MSP.

MC 4.7.8.1. Further an enquiry shall be held by MSP to ascertain if the tampering is indeed deliberate or inadvertent and to ascertain the duration of tempering.

MC 4.7.8.2. If the User's intention of Metering System tampering is proven to be deliberate, then complaint will be lodged to NEPRA and at appropriate law enforcement agency for investigation and/or punitive actions, if any.

MC 4.7.8.3. Metering Data for the period of Metering System tampering, shall be revised and reported by MSP.

MC 5. **ADVANCED METERING INFRASTRUCTURE (AMI)**

MC 5.1. Advanced Metering Infrastructure shall be established to facilitate measurement, recording and transfer of metering data to MO and SO.

MC 5.2. **Parameters shall include following but not limited to:**

(a) Active energy import and export registers

(b) Reactive energy import and export registers

(c) Active import and export billing maximum demand registers (with date-time)

(d) Reactive import and export billing maximum demand registers (with date-time)

(e) 30 minutes (or less-than)timestamped Load Profile data for channels including:

(i) Active Energy Import

(ii) Active Energy Export

(iii) Reactive Energy Import

(iv) Reactive Energy Export

(v) Power Factor each phase

(vi) Voltage each phase

(vii) Current each phase

(f) Meter Local Time

(g) MDI reset counter

(h) Meter Event Log

MC 5.3. MSP shall maintain a complete Metering database (MDM Server) of all Metering Points and incorporate necessary integration parameters such as meter information, metering constants, Instrument Transformer ratios, etc. required for billing and settlement in compliance with Commercial Code.

MC 5.4. MSP shall formulate Standard Operating Procedures (SOPs) for operation and maintenance of the AMI System to achieve uninterrupted and complete meter data retrieval. MSP SOPs shall also cover the following:

a) Meter Data Reading either remotely by MDM, by locally attached device or by hand-held data collection device as required.

b) Meter Data Validation, Estimation & Editing (VEE), refer to MC 5.9

c) Time keeping of Meters

d) Meter Display Parameters

e) Sign conventions

MC 5.5. **Data Communications**

MC 5.5.1. Meters shall be equipped with standard communications ports/modules for local and remote downloading of Load Profile and other Metering Data.

MC 5.5.2. Both the Primary and Backup energy meters shall be integrated in the AMI System of MSP. The relevant User shall be provided with read-only indirect access of Metering Data for its Primary and Backup Meters.

MC 5.5.3. The communication protocol for transmitting Metering Data shall be in accordance with IEC 61107, IEC 62056 (DLMS/COSEM specifications), or IEC 61850. All necessary efforts and best practices shall be employed to ensure the security and integrity of the communication network of meters.

MC 5.5.4. Remote communication option shall be provided by means of GSM/GPRS, Ethernet, V-SAT, SCADA, PLC, external router and/or OPGW/optical fiber.

MC 5.5.5. Remote communication with the meters shall be available to extract data at defined periodic intervals.

MC 5.5.6. In the event of failure of communications facilities, Metering Data shall be read locally from the meter and data be transferred to the Meter Data Management (MDM) Server.

MC 5.6. **Metering Data Storage**

MC 5.6.1. MSP shall retain Metering Data record in MDM Server for at least 5 years. Corresponding storage capacity shall be available in the MSP Server and the Metering Data shall be maintained with a backup arrangement.

MC 5.6.2. The stored Metering Data values shall be in kW and kWh for power and energy respectively.

MC 5.6.3. In the event of a power supply failure, the meters shall protect all data stored up to the time of the failure and maintain the time accuracy.

MC 5.6.4. To cater for continuous supply failures, the clock, calendar and all data shall be retained in meters for a period of 24 months (minimum) without an external supply connected.

MC 5.6.5. Uninterrupted auxiliary supply should be provided to Meters and communication devices for metering and continuous transmission of data;

MC 5.6.6. A “read” action shall not delete or alter any stored Metering Data in the meter and MDM.

MC 5.7. **Meter Time Keeping**

MC 5.7.1. Time of Metering Systems shall be kept synchronized as per Pakistan Standard Time (PST).

MC 5.7.2. Time synchronization of meters may be performed as per MSP SOPs and consequently, appropriate measures be taken to ensure the accuracy of the time-stamped Metering Data.

MC 5.8. **Sharing of Metering Data**

MC 5.8.1. The MSP shall transmit Metering Data to MO for billing and settlement, and if required, to SO for operational monitoring.

MC 5.8.2. MSP shall keep the Metering Data confidential to avoid any unauthorized access by any entity.

MC 5.9. **Metering Data Validation, Estimation, and Editing (VEE)**

MC 5.9.1. MSP shall ascertain that all the Metering Data is complete and correct ensuring that the type, format, frequency, and billing interval of Metering Data is in accordance with the requirements of Commercial Code.

MC 5.9.2. MSP shall follow Metering Data Validation, Estimation & Editing (VEE) process to ensure that:

(a) time stamped Metering Data is properly stored along with status whether read remotely, or by locally attached device.

(b) MSP shall transmit Metering Data to MO clearly marked as "valid" or "invalid" after performing the following Metering Data verifications as a minimum:

(i) Electronic approval of Metering Data by authorized representative of MSP

(ii) Primary vs Backup Metering Data comparison check

(iii) Missing data check

(iv) Abnormal value check

(v) Comparison of totalized/summation of Load Profile intervals energy with the cumulative energy registers of meter

(c) all eventualities affecting Metering Data (e.g. meter testing, metering system errors/faults, etc.) are properly documented and the necessary corrections are incorporated in the meter reading by substitution or estimation. The order of preference for such substitution or estimation shall be:

(i) Corresponding time slot(s) Metering Data from Backup energy meter

(ii) Estimated Meter Reading in agreement and consultation with MSP and the relevant User to be arrived by:

a. computation from other meters at the relevant site and remote ends.
b. Best practice reading estimate by applying necessary corrective adjustments to Primary or Backup Metering Data

MC 5.10. **Dispute in Metering Data**

MC 5.10.1. MSP shall resolve errors/omissions in Metering Data (as a result of metering system error or malfunction) in agreement with the concerned User(s). Once the agreement is reached, the adjusted/corrected Metering Data shall be reported to MO, as appropriate.

MC 5.10.2. In case MSP and the relevant User(s) do not reach an agreement, the Dispute Resolution Procedure as provided for in the Commercial Code shall be followed.

MC 6. **METERING SYSTEM TESTING**

MC 6.1. MSP shall be responsible for testing of Metering System as per the applicable IEC standards, maintain relevant records including but not limited to dates, readings, test results and adjustments if any. Any such record shall be retained for the life of metering equipment or 5 years, whichever is less.

MC 6.2. All equipment used for testing of Metering System shall conform to the applicable IEC standards for the respective equipment and shall have a valid calibration certificate from an authorized entity and/or the relevant accreditation authority.

MC 6.3. Inaccurate or faulty Meter(s) and dedicated metering CT/VT shall be replaced by the respective owner of the equipment, MSP or the User, as the case may be.

MC 6.4. **Commissioning Tests**

MC 6.4.1. Metering System shall be subject to type test and Factory Acceptance Tests (FAT) to ensure compliance of applicable IEC standards.

MC 6.4.2. MSP shall conduct commissioning tests of the Primary and Backup Meters in the presence of authorized representatives of the stakeholders involved.

MC 6.4.3. User shall be responsible for conducting commissioning tests of the dedicated metering CTs/VTs in the presence of authorized representatives of the stakeholders involved.

MC 6.5. **Routine and Off-Schedule Testing**

MC 6.5.1. MSP shall conduct Meter testing periodically at least once in every two years in the presence of authorized representatives of the stakeholders involved.

MC 6.5.2. User shall be responsible for conducting routine and accuracy testing of dedicated metering CTs/VTs at least once in every 5 years in the presence of authorized representatives of the stakeholders involved.

MC 6.5.3. If difference between the Primary and Backup Metering Data is more than ±0.5% for active energy or ±1.5% for reactive energy, then MSP shall take appropriate corrective measures that may include due diligence of connection configurations and/or off-schedule testing of Metering System.

MC 6.5.4. If User suspects accuracy of its Metering System, then it may request for an off-schedule testing at its own cost. However, if as a consequence of such test, the Metering System is found to be inaccurate, the User shall not bear the cost of such tests.

MC 7. **ACCESS TO USER PREMISES**

MC 7.1. MSP shall have the right to enter premises of the relevant User for the purpose of installing, checking, testing and maintaining of Metering System. The User shall co-operate with the MSP in this regard and shall not prevent the MSP from making unscheduled inspections on reasonable prior notice.

MC 7.2. The right of access provided for under this sub-code includes the right to bring on to the User's property such vehicles, test equipment, and maintenance/communication equipment or other materials as may be necessary for the purpose of testing and troubleshooting of Metering System faults.

MC.Annex-1. SCHEDULE OF DATA FOR METERING VOLTAGE TRANSFORMER

'X'- PROPOSED DATA/PARAMETERS BY THE USER SUBMITTED FOR APPROVAL OF MSP

Reference Section No.	**Description**	**'X'**
	Type/Designation of offered VT	
A-1	**RATINGS**	
	Nominal voltage, rms (kV)	
	Rated voltage(Um), rms (kV)	
	Rated Frequency (Hz)	
	No. of Secondary Windings	
	Rated Burden (VA)	
	Accuracy Class	
	Rated Voltage Factor a) Continuous b) 30 seconds	
	Maximum Temperature Rise above on Ambient of 50°C	
	One Minute Power Frequency Withstand Voltage (kV)	
	Rated Lightning Impulse withstand voltage 1.2/50μs, (kV peak) Power Frequency Withstand Secondary Circuit, kV rms	
	Rated switching Impulse Withstand Voltage, kV Peak	
	Nominal Transformation ratios	
	Rated Primary Voltage (Phase to Neutral) kV	
	Rated Secondary Voltage (V)	
	Minimum External Creepage Distance (mm)	
	Short Circuit Impedance(Ω), referred to Secondary (max)	
	Radio Interference Voltage at 1.1. UR/3kV and 1000 kHz. Micro Volts	
	Ambient Conditions: i) Temperature Range (°C) ii) Wind Velocity (Km/h) iii) Earthquake (g)	

	Capacitance: i) High Voltage Capacitor = C1 ii) Intermediate Voltage Capacitor =C2	
A-2	**TYPE TESTS**	
A-2-1	**For Inductive voltage transformer**	
	Measurement of the resistance of primary and secondary windings.	
	Impulse voltage withstand test	
	Power frequency voltage withstand test at Primary & secondary windings, between sections and for earthed terminal(dry).	
	Wet test for outdoor type transformers	
	Partial discharge measurement during induced voltage test.	
	Electromagnetic compatibility (EMC) tests.	
	Temperature-rise test.	
	Measurement of capacitance and dielectric dissipation Factor.	
	Tests for accuracy.	
	Verification of degree of protection by enclosures.	
	Verification of terminal Enclosure tightness test at ambient temperature	
	Pressure test for the enclosure.	
	Short-circuit withstand capability test.	
	Radio Interference Voltage (RIV) Test.	
	Mechanical test.	
	Transmitted Overvoltage Measurement	
	Determination of percentage voltage (ratio) errors and phase displacement at 80%, 100% and 120% of rated voltage, at rated frequency and at 25% and 100% of rated burden for measuring winding and at a power factor of 0.8 lagging for measuring accuracy class.	
A-2-2	**For Capacitive Voltage Transformer**	
	Measurement of resistance of primary and secondary windings	
	Impulse voltage withstand tests on primary terminals	
	Chopped impulse withstand test	
	Power frequency voltage withstand test at primary and	

	secondary windings	
	Wet test	
	Electromagnetic Compatibility Test	
	Temperature rise test	
	Measurement of Capacitance and Dielectric Dissipation Factor	
	Test for accuracy	
	Capacitance and tan ¥ at power frequency	
	Verification of degree of protection by enclosures	
	Enclosure tightness test at ambient Temperature	
	Pressure Test for enclosure	
	Short circuit withstand capability test	
	Ferro-resonance test	
	Partial discharge measurement during induced voltage test	
	Radio interference test (RIV)	
	Mechanical test	
	Transmitted over voltage measurement	
	Determination of percentage voltage (ratio) errors and phase displacement at 80%, 100% and 120% of rated voltage, at rated frequency and at 25% and 100% of rated burden for measuring winding and at a power factor of 0.8 lagging for measuring accuracy class.	

MC.Annex-2. SCHEDULE OF DATA FOR METERING CURRENT TRANSFORMER

'X'- PROPOSED DATA/PARAMETERS BY THE USER SUBMITTED FOR APPROVAL OF MSP

Reference Section No.	Description	'X'
	Type/designation of offered CT	
B-1	**RATINGS**	
	Nominal voltage, rms (kV)	
	Rated voltage (Um), rms (kV)	
	Rated Frequency (Hz)	
	Rated normal primary current (A)	
	Rated secondary current (A)	
	Rated continuous Thermal current, lcth (A)	
	Rated Secondary Output (VA)	
	Instrument Security Factor	
	Accuracy Class	
	Short time current rating (kA):	
	- Thermal,Ith.	
	- Dynamic,Idyn.	
	Lightning/Switching Impulse withstand voltage (Primary winding), (kV)	
	Power frequency withstand Voltage (Primary winding), (kV)	
	Power frequency withstand Voltage (Secondary winding), (kV)	
	Power frequency withstand Voltage between sections, (kV)	
	Resistance of primary winding at 20°C ambient temperature	
	Resistance of secondary winding at 20°C ambient temperature (mΩ)	
	Inter Turn Insulation level (kV)	
	C & DF, (tan δ)	
	Max. Radio Interference Level (RIV) at 1.1Um/√3, (μV)	
	Rated Mechanical Static Withstand load **(N)**	
	Rated Mechanical Dynamic Withstand load **(N)**	
	Temperature rise of winding(50^{o}C Ambient)	
	Temperature rise of top oil(50^{o}C Ambient	
	Rated duration of short circuit (Sec.)	
B-2	**TYPE TESTS**	
	Copy of type test reports attached (Yes/No)	
	Rated Voltage (kV)	
	Rated normal primary current (A)	
	Rated secondary currents (A)	
	Rated short time withstand current for 1 sec, rms (kA)	

	Rated peak withstand current, rms (kA)	
	Resistance of primary winding (µO)	
	Resistance of secondary winding (mΩ)	
	Temperature rise of winding(^{0}C)	
	Temperature rise of top oil(^{0}C)	
B-3	**DETAILS OF FOLLOWING TYPE TEST IF PERFORMED**	
	Measurement of the resistance of primary and secondary windings	
	Lightning impulse withstand voltage test on primary	
	Power frequency voltage withstand test at Primary & secondary windings and between sections	
	Wet test for outdoor type transformer	
	Inter-turn over voltage test	
	Partial discharge Measurement.	
	Radio Interference Voltage (RIV) test	
	Temperature-Rise test	
	Short-time withstand current and peak withstand current tests	
	Measurement of capacitance and dielectric dissipation factor test	
	Mechanical tests	
	Determination of errors before and after short circuit test.	
	Verification of degree of protection	
	Enclosure tightness test at ambient temperature	
	Pressure test for enclosure	

MC.Annex-3. SCHEDULE OF DATA FOR ENERGY METERS

PROPOSED DATA/PARAMETERS BY THE USER SUBMITTED FOR APPROVAL OF MSP

Basic Requirement:

(i) Provided energy meter **MUST** be capable of integration with the MDM Server of MSP. All the necessary communication modules required for this **integration shall be provided by User**.

Sr.No.	**Description**			
1.	Manufacturer's name			
2.	Manufacturer's address. (Attach Manufacturer's catalogue with the bid)			
3.	Type/designation/Model No. of offered meter (complete ordering code).			
4.	Country of origin.			
5.	Accuracy class of Energy Meter on which following type tests were performed.			
6.	Type/designation of Energy Meter on which following type tests were performed.			
			Date of Test	**Name of Lab.**
	A **Tests of mechanical requirements.**			
	-	Spring hammer test.		
	-	Vibration test.		
	-	Test of resistance to heat and fire.		
	-	Test of protection against penetration of dust and water.		
	B **Test of climate influence**			
	-	Dry heat test.		
	-	Cold test.		
	-	Damp heat cyclic test.		
	-	Solar radiation test.		
	C **Tests of electrical requirements**			
	-	Test of power consumption of voltage circuit		
	-	Test of power consumption of current circuit.		
	-	Test of effect of voltage dips and short interruptions.		
	-	Test of influence of short time over current.		
	-	Test of influence of self-heating.		
	-	Test of influence of heating.		
	-	Impulse voltage test.		
	-	A.C. voltage test.		
	D **Tests for electromagnetic compatibility (EMC)**			
	-	Test of immunity to electrostatic discharges.		
	-	Test of immunity to electromagnetic RF fields.		
	-	Fast transient burst test.		
	-	Test of immunity to conducted disturbances, induced by radio-frequency fields.		
	-	Surge immunity test.		

	-	Damped oscillatory waves immunity test.		
	-	Radio interference suppression test.		
	F	**Tests of Accuracy requirements**		
		Test of Accuracy.		
		Test of influence quantities.		
		Test of ambient temperature influence.		
		Test of no load condition.		
		Test of starting condition.		
7.	Accuracy Class (Active/Reactive) of the offered energy meter.			
8.	Capability of offered energy meter to record:			
	-	Active Energy Export	YES/NO	
	-	Reactive Energy Export	YES/NO	
	-	Active Energy Import	YES/NO	
	-	Reactive Energy Import	YES/NO	
	-	Apparent Energy	YES/NO	
	-	Maximum Demand of Active Energy	YES/NO	
	-	Maximum Demand of Reactive Energy	YES/NO	
	-	Maximum Demand of Apparent Energy	YES/NO	
	-	Active Energy	YES/NO	
	-	Reactive Energy	YES/NO	
	-	Apparent Energy	YES/NO	
9.	Whether reactive energy measurement is stored in separate displayable registers?		YES/NO	
10.	Permissible min/max ambient temperature:			
	-	During operation	^oC	
	-	During storage	^oC	
	-	During operation	^oC	
11.	No. of phases.		Nos.	
12.	No. of wires.		Nos.	
13.	No. of elements		Nos.	
14.	Reference Voltage (U)		Volts	
15.	Reference Temperature.		^oC	
16.	Reference frequency (f)		Hz	
17.	Rated current, In.		Amp	
18.	Maximum current, Imax..		Amp	
19.	Impulse withstand voltage.		kV	
20.	AC withstand voltage.		kV	
21.	Temperature-rise of the meter.		^oC	
22.	Whether meter operates continuously at 1.2 In?		YES/NO	
23.	Sampling rate			
24.	IP class of the meter.			
25.	Main power supply voltage of the meter.		Volts	
26.	Material of terminal block			
26.	Material of case			
27.	Material of terminal cover			
28.	Whether the arrangements as required are available on the front cover? In case of anynon-conformance, give details.		YES/NO	
29.	Whether terminal cover meet the requirement of ISO 75, temp. of 135 & a pressure of 1.8M Pa.		YES/NO	

30.	Type of display.		LCD/LEDs	
31.	No. of digits of display.		Nos.	
32.	Size of digits of display (H x W)		Mm	
33.	Minimum retention period of back up non- volatile memory.		Months	
34.	Type of Memory.			
35.	Memory storage capacity of display unit.		Bytes	
36.	Memory storage capacity of each register.		Bytes	
37.	Memory capacity for load profile.		Bytes	
38.	Total memory storage capacity of all register.		Bytes	
39.	Overall memory capacity for energy meter.		Bytes	
40.	Minimum retention period of display unit.			
41.	Minimum retention period of registers.			
42.	Minimum numbers of programmable display modes.		Nos.	
43.	Battery life for display unit.			
45.	Whether facility for activating the display is provided on the front of the meter?		YES/NO	
45.	Whether display unit is reactivated in case failure of main/auxiliary supply?		YES/NO	
46.	Whether display unit is able to record & display data for a minimum period of 120 days corresponding to max. current at reference voltage and unity power factor?			
47.	Whether following data/information is displayed on with date & time stamped?			
	-	Date and time	YES/NO	
	-	CT & PT ratio	YES/NO	
	-	Phase/Line voltages	YES/NO	
	-	Phase/Line currents	YES/NO	
	-	Active energies import and export (present & preceding month), KWH.	YES/NO	
	-	Reactive energies import and export (present & preceding month), KVARH.	YES/NO	
	-	Apparent energies import and export (present & preceding month), KVAH.	YES/NO	
	-	Max. Demand of Active energies import and export (present & preceding month), KW.	YES/NO	
	-	Max. Demand of Reactive energies import and export (present & preceding month), KVAR.	YES/NO	
	-	Max. Demand Apparent energies import and export (present & preceding month), KVA.	YES/NO	
	-	Power factor, PF.	YES/NO	
	-	Frequency, Hz.	YES/NO	
	-	Last Max. Demand reset	YES/NO	
	-	Total No. of Max. Demands resets	YES/NO	
	-	Meter serial No.	YES/NO	
	-	Power Quadrant Indicator.	YES/NO	
	-	Pulse Output for field testing of meter	YES/NO	
	-	Error code	YES/NO	
48.	Pulse outputs for remote metering:-			
	-	Type of outputs.		
	-	VA burden of outputs.		

	-	No. of output terminals.		
	-	Number of pulse outputs		
	-	Pulse width, amplitude		
	-	Whether pulse rate fixed/programmable?		
49.	Whether information as required is marked on the energy meter? In case of any non-conformance, give details.		YES/NO	
50.	Whether flashing LED indicators are provided on the meter for accuracy measurement?		YES/NO	
51.	Whether the flashing rate of LED is programmable?		YES/NO	
52.	Meter constant, imp/KWH/KVARH.		Nos.	
53.	Whether provision to program the meter is available for any combination of CT & PT transformation ratios?		YES/NO	
54.	Whether facility to select different integration times ranging from 5 to 60 minutes, separately for maximum demand and load profile is provided?		YES/NO	
55.	Whether energy meter designation/model, accuracy class and Serial No. of the meter printed/marked at the front frame is stored in the non-volatile memory and is retrievable through meter software?		YES/NO	
56.	Normal operating voltage range		Volts	
57.	Limit range of voltage operation		Volts	
58.	Power consumption.			
	-	Voltage circuits	VA	
	-	Current circuits	VA	
	-	Auxiliary power supply	VA	
59.	Permissible short time (0.5s) over-current			
60.	Minimum starting current		mA	
61.	Initial start-up time		ms.	
62.	Meter Clock			
	-	Accuracy of real time clock		
	-	Type of battery.		
	-	Battery voltage.	V	
	-	Life of battery.	Years	
	-	No. of programmable dates to account for holidays and weekends.		
63.	No. of Tariffs		Nos.	
64.	Type of Tariffs			
65.	No. of registers		Nos.	
66.	Whether meter record the following events with Date and Time Stamped?			
	-	Main supply failure.	YES/NO	
	-	Main supply restored.	YES/NO	
	-	Phase voltage failure.	YES/NO	
	-	Phase voltage restored.	YES/NO	
	-	Per phase current loss.	YES/NO	
	-	Per phase current restored	YES/NO	
	-	Disconnection of wires including neutral wire.	YES/NO	
	-	Restoration of wires including neutral wire.	YES/NO	

	-	Total number of power outages.	YES/NO	
	-	Reverse energy flow.	YES/NO	
	-	Reverse Polarity/CT reversal.	YES/NO	
	-	Last meter programming.	YES/NO	
	-	Last meter clock programming.	YES/NO	
	-	Low battery.	YES/NO	
	-	Current in-balance.	YES/NO	
	-	Over/under voltage.	YES/NO	
	-	Open case.	YES/NO	
	-	Open cover.	YES/NO	
	-	Open terminal cover.	YES/NO	
	-	Last billing reset.	YES/NO	
	-	Total count of strong external magnetic field influence.	YES/NO	
	-	Last four months billing Data, KWH & KVARH,	YES/NO	
	-	Last four months billing Data, KW & KVAR.	YES/NO	
	-	Last four months billing Data, KVA & KVAH.	YES/NO	
67.	Type of metrology indicator (visible light/IR)			
68.	Type/arrangement of voltage loss indication			
69.	Accuracy curves (attached)		YES/NO	
70.	Whether energy meter have the following security features with Date and Time Stamped and can be verified through software?			
	-	Sr. No. in its memory and displayed.	YES/NO	
	-	The No. of times programmed.	YES/NO	
	-	Identification of the last programmer.	YES/NO	
	-	A programmable meter ID code.	YES/NO	
	-	A meter reader ID code.	YES/NO	
	-	Meter keep on recording/operating as long as any phase voltage exists with neutral connected.	YES/NO	
	-	Meter keep on recording/operating as long as any phase voltage exists without neutral connected.	YES/NO	
	-	The meter is protected against loss of data and functional performance due to external interference such as influence of Strong/ Radar Magnet, CD drive, Mobile phones.	YES/NO	
71.	EMC Electrostatic discharge.		kV	
72.	VF magnetic field withstand level.		V/m	
73.	Whether meter have upgraded option.		YES/NO	
74.	Type of modem if supplied.			
75.	Whether offered energy meter comply with DLMS/COSEM/SCADA protocols.		YES/NO	
76.	Dimensions of energy meter (attach drawing)			

DATA REGISTRATION CODE

DRC 1. **INTRODUCTION**

DRC 1.1. The Data Registration Code (DRC) presents a unified listing of all data required by the System Operator (SO) from Users and vice versa, from time to time under the Grid Code. The data is specified in each sub-code of the Grid Code and gathered here in the DRC. Where there is any inconsistency/conflict in the provisions and/or data requirements under DRC with another sub-code, the provisions of the respective sub-code of the Grid Code shall prevail.

DRC 1.2. The specific procedures and timelines for the submission of DRC data, for routine updating, and recording temporary or permanent changes to the data, are specified in the respective sub-codes under which any item of the data is required.

DRC 1.3. The SO reserves the right to ask for any other data not listed in the DRC or in any sub-code of the Grid Code as per its requirement.

DRC 2. **SCOPE**

This sub-code is applicable to the following Users:

(a) System Operator;

(b) Transmission Network Operators (NGC, PGCs, RGCs, SPTLs, DISCOs, etc.);

(c) Transmission-connected Generators;

(d) Transmission-connected Consumers;

(e) Interconnectors (both AC & HVDC);

(f) Energy Storage Units;

(g) Demand Side Units (DISCOs, Suppliers, BPCs);

(h) Meter Service Provider (MSP);

(i) Distribution Network Operators (DNO)

(j) Market Operator (MO);

(k) Small/Embedded generators whether represented through some Aggregators or any other arrangement (if required by SO); and

(l) Third parties contracted by any User.

DRC 3. **DATA CATEGORIES FOR REGISTRATION**

DRC 3.1. Each data item is allocated to five categories and annexed with the respective sub-code:

(a) Planning Code (PC) Data list mentioned in Schedule I

(b) Connection Code (CC) Data list mentioned in Schedule II

(c) Operation Code (OC) Data list mentioned in Schedule III

(d) Scheduling and Dispatch Code (SDC) Data list mentioned in Schedule IV

(e) Metering Code (MC) Data list mentioned in Schedule V

DRC 4.	**PROCEDURES AND RESPONSIBILITIES**
DRC 4.1.	**Responsibility for Submission of Data**
	User shall submit data as summarised in DRC in accordance with the provisions of the various sub-codes of the Grid Code.
DRC 4.2.	**Methods of submitting Data**
DRC 4.2.1.	The data requirements annexed with the sub-codes are structured to serve as standard templates for the data submission in written format to the SO.
DRC 4.2.2.	Data shall be submitted to the SO, or to any other entity (TNO, MSP, NGC, etc.) as advised by the SO. The name of the person submitting the schedule of data on the behalf of the User shall be included.
DRC 4.2.3.	Subject to SO's prior written consent, where a computer or electronic data exchange link exists between a User and SO, the data can be submitted via this link.
DRC 4.3.	**Changes to User's Data**
	The User must notify SO whenever the User becomes aware of change to any item of the data which is registered with the SO.
DRC 4.4.	**Data not supplied**
DRC 4.4.1.	User and SO are responsible to submit data as set out in the sub-codes of the Grid Code and mentioned in the DRC.
DRC 4.4.2.	If User fails to submit the data as per DRC requirements even after the SO's reminder notice, SO shall make an estimation (typical values) of such data, if and when, in the SO's view, it is necessary to do so.
DRC 4.4.3.	If SO fails to provide the data as per requirements of any sub-code of the Grid Code, the User to whom that data ought to have been provided, shall estimate (typical values) of such data, if and when, in that User's view it is necessary to do so.
DRC 4.4.4.	Such estimates shall, in each case, be based upon data supplied previously for the same Plant and Apparatus or upon such other information as SO or that User, as the case may be, deems appropriate.
DRC 4.4.5.	In the event of data not being provided, SO shall inform the User in writing of any estimated data it intends to use pursuant to DRC 4.4.2.
DRC 4.4.6.	In the event of data not being provided, the User shall inform SO in writing of any estimated data it intends to use pursuant to DRC 4.4.3.
DRC 4.4.7.	In the event the required data is consistently not submitted, or is incomplete or inaccurate, by the User, the SO shall refer the matter to the "Grid Code Review Panel", which shall issue necessary instructions to the defaulting party in writing.
DRC 4.4.8.	In the event the required data is consistently not submitted, or is incomplete or inaccurate, by the SO, the User shall refer the matter to the "Grid Code Review Panel", which shall issue necessary instructions to the defaulting party in writing.

DRC 4.4.9. Failure to obtain the required data within the specified timeframes from the defaulting party, NEPRA shall consider the matter as a violation of the Grid Code provisions. Suitable measures as specified in CM 15 regarding Grid Code non-compliance shall be used.

DRC 4.5. **Confidentiality Obligations**

Users shall use their best efforts to stop the disclosure of any of the confidential information which comes into the possession or control of that User or of which the User becomes aware of. The User:

(a) must not disclose confidential information to any person except as permitted by the Grid Code;

(b) must only use or reproduce confidential information for the purpose for which it was disclosed, or another purpose contemplated by the Grid Code;

(c) must not permit unauthorized persons to have access to confidential information.

(d) to prevent unauthorized access to confidential information which is in the possession or control of that User; and

(e) to ensure that any person to whom it rightfully discloses confidential information observes the provisions of Grid Code.

DRC 5. **DATA TO BE REGISTERED**

DRC 5.1. **Schedules I to V cover the following data areas:**

DRC 5.1.1. **SCHEDULE I - Planning Code Data**

Standard Planning schedules comprising of data including General Information, User System Data (Maps and Diagrams), Licensing and Authorization, User System Layout (Single Line Diagrams, Circuit Parameters, Lumped System, Susceptance, Reactive Compensation Equipment and Short-Circuit Contribution to TNO/DISCO Transmission System), Data Required for Load Forecasting and Data Requirement for Generation Capacity Expansion Plans.

Project Planning schedules comprising of data including Generator Data (Generator Unit Details, Excitation System Parameters, Speed Governor System, Power System Stabilizers), Controllable Solar, Wind and ESPP (SWE) Data Requirements (SWE Generators Parameters, Mechanical parameters, Aerodynamic performance, Reactive Power Compensation, Control and Protection systems, Internal network of Controllable SWE, Flicker and Harmonics and Short Circuit Contribution and Power Quality) and Interconnector Data Requirements (Interconnector Operating Characteristics and Registered Data).

DRC 5.1.2. **SCHEDULE II – Connection Code Data**

Connection Code schedules comprises of data including list of minimum requirements for power system And Apparatus Connected to the Transmission Systems, Grid Station Information, DC Convertor Station, Power Generators Unit Data, Generator (Unit) Transformer, Excitation System (AVR and Exciter

Parameters), Generating Unit Stabilizer Data, Governor Data, Prime Mover Data, Wind Turbine Generator, Transmission Lines Data, Power Transformer Data, Busbar Data, Circuit Beaker Data, Isolator Data, Shunt Reactor Data, Proforma for Site Responsibility Schedule (SRS), Principles and Procedures Relating to Operation Diagrams, Appendix Principles and Procedures Relating to Gas Zone Diagrams, Apparatus to be Shown on the Operation and Gas Zone Diagrams, Minimum Frequency Response Requirements Scope, Technical Requirements for Low Frequency Relays for the Automatic Load Shedding, SCADA Signals to be Provided by Users (Status Indication Signals, Measurement Signals, Control Signals, Protection Signals, Other Signals, Signals related to Generators, Signal related to Demand Side Units and Signals related to AC and HVDC Interconnectors), Voltage against Time Profile.

DRC 5.1.3. **SCHEDULE III – Operation Code Data**

Operation Code schedules comprises of data including Emergency Manual Demand Reduction/Disconnection, Short Term Planning Timetable for Generation Outages, Medium Term Planning Timetable for Generation Outages, Long Term Planning Timetable for Generation Outages, Transmission Outages, Generator Performance Chart, Generation Planning Parameters, Technical Parameters - RES/BESS, Technical Parameters – Interconnectors, Response data for Frequency Changes, Primary Response to Frequency Fall, Secondary Response to Frequency Fall, High Response to Frequency Rise, Generator, Governor and Droop Characteristics, Unit Control Options, Control of Load Demand, Significant System Incident, System Warnings, Inter-System Safety record of Inter-Safety Precautions (RISSP - R), Inter-System Safety record of Inter-Safety Precautions (RISSP - R).

DRC 5.1.4. **SCHEDULE IV – Schedule and Dispatch Code Data**

Schedule and Dispatch Code schedules comprises of data including Technical Parameters, Availability Notice, Notification of Revised Availability Notice, Technical Parameters Revision Notice and Dispatch Instructions for CDGUs and Demand Side Units.

DRC 5.1.5. **SCHEDULE V – Metering Code Data**

Metering Code schedules comprises of data including Technical Parameters for Metering Voltage Transformer and Metering Current Transformer.

DRC 5.2. If at any time, SO considers that the Schedules do not reflect the operative provisions relating to the submission of data, the SO may, by notice in writing to all affected User amend the Schedules to this DRC.

DRC 5.3. No changes may be made in DRC schedules which would affect the substantive obligations of the Users. Changes of this nature can only be achieved by means of the usual procedure for Grid Code changes and will require the approval of NEPRA.

DEFINITIONS

Term	Definition
Act	The Regulation of Generation, Transmission and Distribution Electric Power Act, 1997 (XL of 1997).
Active Energy	The electrical energy produced, flowing or supplied by an electrical 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.
Active Power	The product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof.
Advanced Metering Infrastructure or AMI or Secured Metering System or SMS	The system, including hardware, software and communication channels, which retrieves information from the Metering System and transfers it electronically at specified times.
Affected User	A User, affected by Operation, Event or Significant Incident, who provides evidence in the matter to the satisfaction of SO.
AGC Control Range	The range of loads over which AGC may be applied.
AGC Maximum	The upper limit of the AGC Control Range.
AGC Minimum	The lower limit of the AGC Control Range.
Aggregated Generating Unit	A group of Generating Units represented by a Generator Aggregator.
Aggregators	Either a Generator Aggregator or a Demand Side Unit in respect of an Aggregated Demand Site.
Agreement(s)	A negotiated and typically legally binding arrangement between parties as to a course of action such as PPAs, PSODA, TSAs, Connection Agreement(s), etc.
Alert	An Alert warning issued pursuant to OC-12.
Amendment	A change or modification in any provision(s) of the Grid Code, but not the Grid Code in its entirety, recommended by Grid Code Review Panel and approved by the NEPRA.
Ancillary Services	A service, other than the production of electricity, which is used to operate a stable and secure Power System such as Reactive Power, Operating Reserve, Frequency Control and Black start Capability, which is compensated through Commercial Code.
Apparatus	All electrical equipment connected with Power System.
Apparent Power	The product of voltage and of alternating current measured in units of Volt-amperes and standard multiples thereof.
Authority	The National Electric Power Regulatory Authority constituted under section 3 of the Act.
Automatic Generation Control (AGC)	A control system installed between the SO and User whereby MW set points can be adjusted remotely by the SO to reflect the Dispatch Instruction.
Automatic Low Frequency	The automatic disconnection of Demand when the Frequency or the

Term	Definition
Demand Disconnection	rate of change of frequency has violated acceptable limits as determined by the SO.
Automatic Low Voltage Demand Disconnection (ALVDD)	The automatic disconnection of Demand when the Voltage has violated acceptable limits as determined by the SO.
Automatic Meter Reading (AMR)	A technology of automatically collecting consumption, diagnostic, and status data from energy metering devices and transferring that data to a central database for billing, troubleshooting, and analyzing.
Automatic Reactive Power Regulator	A continuously acting automatic control system which acts to control the reactive power exchange with the System according to instructed modes and set points.
Automatic Voltage Regulator (AVR)	A continuously acting automatic excitation control system to control the voltage of a Generator measured at the Generator terminals.
Auxiliaries	Any item of Plant and Apparatus of Generator not directly a part of the Generator, but required for its functional operation. “Auxiliary” shall be construed accordingly.
Availability	At any given time the measure of Active Power a Generating Unit(s) is capable of delivering to the Connection Point. In terms of a Demand Side Unit, the Demand Side Unit MW Capacity as the measure at any given time of the capability of the Demand Side Unit to receive from the System. At any given time, the measure of Active Power an Interconnector is capable of importing to or exporting from the Connection Point. The term “Availabilities” and “Available” shall be construed accordingly
Availability Factor	The ratio of the Energy that could have been produced during a specified period of time by a Generating Unit operating in accordance with its Availability, and the Energy that could have been produced during the same period by that Generating Unit operating at its Registered Capacity.
Availability Notice	A notice to be submitted to the SO pursuant to SDC1.
Available Transfer Capability	Effective power that can be imported from or exported to an Interconnector for load dispatch.
Average Conditions	The combination of elements within a period of time which is the average of the observed values of those elements during equivalent periods over many years.
Ancillary Services	Services supplied to the SO by Users, necessary for the reliable and secure transport of power from Generators to consumers which include those which must be provided by Users in accordance with the Connection Code and those which must be provided by a User if the User has agreed to provide them under supplemental agreements
Back-up Control Center	The stand-by Control Center of SO to be used as an alternative if it’s

Term	Definition
	Main Control Center fails or is rendered un-operational.
Back-up Meter	A backup device used to record electrical quantities such as energy, MDI etc. consumed by a USER along with time stamped events.
Back-up Metering System	A complete backup metering system installed at the Metering Point such as metering CT, VT, Meter, communication equipment and secondary circuits of instrument transformers including interconnecting cables; wires, metering cabinets and associated devices.
Back-up Protection	Protection equipment or system which is intended to operate when a system fault is not cleared in due time because of failure or inability of the primary or main protection scheme to operate or in case of failure to operate a circuit-breaker other than the associated circuit-breaker.
Base Case	System's software model for a particular project under study.
Black Start	The procedure necessary for a recovery of Power System from a Total Shutdown or Partial Shutdown.
Black Start Capability	The ability of a Generator to start up at least one of its Generating Units from Shutdown; and to energize a part of the National Grid and/or be synchronized to the National Grid on the instructions of System Operator, without any external electrical power supply
Black Start Station	Black start stations are designated Generators with Black Start Capability. An emergency auxiliary (station service) supply, such as auxiliary diesel-electric generator capable of supplying auxiliary power to the station is provided.
Black Start Test	A test carried out by a User on the instructions of SO to demonstrate that the designated Black Start Station has a Black Start Capability.
Block Load	The level of output that a Generating Unit/ Interconnector immediately produces following Synchronization. The term "Block Loading" shall be construed accordingly.
Block Load Cold	Block Load during a Cold Start.
Block Load Hot	Block Load during a Hot Start.
Block Load Warm	Block Load during a Warm Start.
Bulk Power Consumer (BPC)	A consumer who purchases or receives electric power, at one premises, in an amount of one megawatt or more or in such other amount and voltage level and with such other characteristics as the NEPRA may specify and the NEPRA may specify different amounts and voltage levels and with such other characteristics for different areas.
Cancelled Start	A response by a Generator to an instruction from the SO cancelling a previous instruction to Synchronize to the Transmission System.
Capability Curve	The Curve of equipment that defines the boundaries within which it can deliver Active and Reactive Power continuously without

Term	Definition
	overheating/ damaging.
Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
Capacity Adequacy	A condition when there is sufficient Generation Capacity to meet the Demand and Reserve requirements.
Capacity Certificate	As defined in Commercial Code.
Cascading Outage	The uncontrolled successive loss of system components triggered by an incident at any location.
CCGT Installation Matrix	The matrix which must be submitted by a CCGT installation which is used by the SO for Scheduling and Dispatch purposes under the SDC as a "look up" table determining which CCGT Units will be operating at any given MW Dispatch level subject to any updated Availability information submitted by a Generator to a SO under SDC1.
CCGT Installation/ Complex	A collection of Generating Units comprising one or more Combustion Turbine Units and one or more Steam Units where, in normal operation, the waste heat from the Combustion Turbine Units is passed to the water/steam system of the associated Steam Unit or Steam Units and where the component Generating Units within the CCGT Installation 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 Installation/ Complex.
CCGT Unit	A Generating Unit within a CCGT Installation
Central Dispatch	The process of Scheduling and issuing Dispatch Instructions directly to a Control Facility by the SO pursuant to the Grid Code.
Centrally Dispatched Generating Unit	A Generating Unit within a Generator subject to Central Dispatch. Further elaborated in SDC.1
Charging Capacity	The maximum amount of Energy consumed by Energy Storage Unit when acting as a Demand.
Code Participant	All entities subject to Grid Code.
Cold Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time longer than its submitted Warm Cooling time.
Combustion Turbine Units	Generation Unit which compresses the inlet air and feeds fuel to the combustion chamber. The fuel and air burn to form hot gases which in turn forces these hot gases into the turbine, causing it to spin. The turbine can be fueled by natural gas, by distillate or by other such fuels as technology may allow.
Commercial Code	A document that governs the form and manner in which the Market Operator shall undertake its licensed activities as per Act
Commercial Metering	Metering which is utilized for Tariff charging purpose.

Term	Definition
Commissioning	Activities involved in undertaking the Commissioning Test or implementing the Commissioning Instructions pursuant to the terms of the Agreement(s) or as the context requires the testing of any item of Users equipment required pursuant to this Grid Code prior to connection or re-connection in order to determine that it meets all requirements and standards for connection to the Transmission System.
Commissioning Instructions	A step-by-step test procedure for a Commissioning Test.
Commissioning Test	Testing of a User or an item of User's Equipment required pursuant to the Connection Conditions prior to connection or re-connection in order to determine whether or not it is suitable for connection to the System and also to determine the new values of parameters to apply to it following a material alteration or modification of a User or of an item of User's Equipment and the term "Commissioning Testing" shall be construed accordingly.
Committed Outage Program	The Outage Program that the SO shall prepare for the period up to end of Year 1.
Congestion	A constraint resulting from overloading of Equipment which could jeopardize the system security and integrity.
Connection Agreement	An Agreement between Users setting out the terms and conditions relating to a Connection to and use of Transmission System.
Connection	The installation of electrical Equipment used to affect a connection of a User's System to the Transmission System in such a way that, subject to energization, the User may exchange electricity to or from the Transmission System at the Connection Point. The term "Connected" shall be construed accordingly.
Connection Date/ Operational Date	The date on which the Commissioning Instructions have been properly implemented in respect of every part of the User's Equipment to the satisfaction of SO, following which the SO shall, as soon as reasonably practicable notify the User to that effect, specifying the date of completion of such implementation.
Connection Point	A physical point at which a User's Plant and Apparatus connects to the Transmission System.
Connection Site	A site containing a Connection Point.
Consumer/ Customer / End User	Means a person or his successor-in-interest who purchases or receives electric power for consumption and not for delivery or re-sale to others, including a person who owns or occupies a premises where electric power is supplied.
Contingency	The unexpected failure or Outage of a system component, such as a Generating Unit, transmission line, circuit breaker, switch, or other electrical element. A Contingency also may include multiple components, which are related by situations leading to simultaneous

Term	Definition
	component outages.
Control Action	An action, such as switching, whereby the Transmission System is operated.
Control Area	A coherent part of the Power System operated by a single System Operator with physical loads and controllable Generating Units connected within it.
Control Centre	An SO location used for the purpose of monitoring, control and operation of the Transmission System or a User System and for issuing Dispatch Instructions/ Control Actions by SO via Electronic Interface or any other such agreed means.
Control Facility	A User's location used for the purpose of Monitoring, control and operation of the User 's Plant and Apparatus and for accepting Dispatch Instructions via Electronic Interface.
Control Phase	The Control Phase follows on from the Operational Phase and covers the period from Day Ahead down to the real time.
Control Synchronizing	The coupling (by manual or automatic closing of the circuit breaker) of two asynchronous Systems by means of synchroscope
Controllable Solar, Wind & ESPP/ESU (SWE)	Solar, Wind and ESPP/ESU which output can remotely be changed according to the minimum technical requirements.
Critical Loading	This refers to the condition where the loading of transmission lines or substation Equipment is between 90 percent and 100 percent of the continuous rating.
Cyber Asset	Any programmable electronic device, including hardware, software, information, or any of the foregoing, which are components of such devices or enable such devices to function.
Cyber Security	The application of technologies, processes and controls to protect systems, networks, programs, devices and data from cyber-attacks.
Cycle Efficiency of ESU, BESS	The energy efficiency of an ESU over a complete cycle of charging and discharging.
Cycle Operating Mode	The Open Cycle Mode or combine cycle Operating Mode of a CCGT Installation which may need to be specified pursuant to a Dispatch Instruction under SDC2.
Day Ahead	Pertaining to the next Scheduled Day
Daylight Saving Time	The practice of advancing clocks during different months so that darkness falls at a later clock time.
Deadband	A band of input values in a control system or signal processing system where there is no response.
Declaration	A notice prepared by the User submitted to the SO setting out the values (and times applicable to those values) of Availability, Ancillary Services capabilities, Operating Characteristics, and "Declared" shall be

Term	Definition
	construed accordingly.
Declared Available Capacity	The Availability Declared by a User.
De-Energize/Disconnect	Disconnect from the Transmission System utilizing circuit switches etc. to isolate the Plant and/or Apparatus, and “De-energized” and “De-energizing” shall be construed accordingly.
Defense Plan	The set of manual or automatic control actions, defined in sequence by each system operator aimed at mitigating the consequences of exceptional contingencies.
Delivery Point	A Connection Point at which electric energy flows from an HVDC system into the Transmission System.
Deload Break Point	The point at which due to technical reason a Generating Unit may need to pause during its MW output reduction process.
Deloading Rate	The rate at which a Generating Unit reduces MW Output from Minimum Generation to zero when it is instructed to cease output.
Demand	The amount of electrical power consumed by the Power System comprising of both Active and Reactive Power, unless otherwise stated.
Demand Control	The reduction in Demand when the Grid is in an Emergency State. This includes Automatic Load Dropping, Manual Load Dropping, Demand reduction upon instruction by the System Operator .
Demand Forecast	The projections of Power and Active Energy requirements relating to a Connection Point in the Transmission System. The term “Forecasted Demand” shall be construed accordingly.
Demand Management	All actions taken for Demand Control and Demand Response are collectively called Demand Management as explained in OC.3.
Demand Response	The agreed, voluntary self-reduction of Demand by identified Users to assist in System Emergency Conditions.
Demand Side Unit DSU	DISCOs, Bulk Power Consumers connected to Transmission system, Suppliers are collectively called Demand Side Unit.
Demand Side Unit MW Availability	The Notice which must be submitted by the User to the SO in an Availability Notice under SDC1.
Demand Side Unit MW Response	The proportion (in MW) of the Demand Response that is delivered at a given time following a Dispatch Instruction from the SO.
Demand Side Unit MW Response Time	The time as specified by the Demand Side Unit in the Technical Parameter and is the time it takes for the Demand Side Unit to be able to implement the Demand Side Unit MW Response from receipt of the Dispatch Instruction from the SO.
Demand Side Unit Notice Time	The time as specified by the Demand Side Unit in the Technical Parameter and is the time it takes for the Demand Side Unit to begin ramping to the Demand Side Unit MW Response from receipt of the

Term	Definition
	Dispatch Instruction from the SO.
Derogation	Suspension or suppression of any provision(s) of the Grid Code for a specific Code Participant recommended by Grid Code Review Panel and approved by the NEPRA.
Designated Control Center	The central location approved in writing by the SO as its Control Center(s).
Designated Control Facility	The central location communicated in writing by the User to SO as its Control Facility.
Designated Safety Operator	The operators approved in writing by the relevant User as competent to carry out the Safety procedure given in OC 13.
De-Synchronize	The act of taking a Generating Unit/ Interconnector which is Synchronized to the Transmission System off the Transmission System to which it has been Synchronized and the term "De-Synchronized", "De-Synchronization" and other like terms, shall be construed accordingly.
Discipline of the Transmission System	Practice of making Stakeholders obey to rules or standards for the benefit of Transmission System Operation
Dispatch	The process of apportioning the total Demand of the System through the issuance of Dispatch Instructions to the Users in order to achieve the operational requirements of balancing Demand with Generation and Ancillary services that will ensure the Security of the Transmission System.
Dispatch Instruction	An instruction given by the SO to a User under SDC for Dispatch. "Instruct" and "Instructed" shall be construed accordingly.
Dispute Resolution Procedure	A procedure to resolve disputes among the Users.
Distribution	The ownership, operation, management or control of distribution facilities for the movement or deliver or sale to consumers of electric power but shall not include the ownership, operation, management and control of distribution facilities located on private property and used solely to move or deliver electric power to the person owning, operating, managing and controlling those facilities or to tenants thereof.
Distribution Code	The code, approved by NEPRA that defines the technical and operational aspects of the relationship between Distribution Company and all those entities connected to Distribution System.
Distribution Company	An entity licensed by NEPRA to engage in the distribution of electric power.
Distribution Network Operator (DNO)	An entity, which owns, operates and maintains Distribution Facilities.
Dwell Time Down	The duration for which the Generating Unit must remain at the Dwell Time Down Trigger Point during a change in its MW Output while ramping down between instructed MW output and Minimum

Term	Definition
	Generation.
Dwell Time Down Trigger Point	A constant MW level at which a Generating Unit must remain while ramping down between instructed MW output and Minimum Generation.
Dwell Time Up	The duration for which the Generating Unit must remain at the Dwell Time Up Trigger Point during a change in its MW output while ramping up between Minimum Generation and instructed MW output.
Dwell Time Up Trigger Point	A constant MW level at which a Generating Unit must remain while ramping up between Minimum Generation and instructed MW output.
Earth Fault Factor	The ratio of the highest power-frequency phase to earth voltage on a healthy phase during an earth fault to the power frequency phase to earth voltage in absence of the fault at the same location in the system
Earthing	A way of providing a connection between conductors and earth by an Earthing Device.
Earthing Device	A means of providing a connection between a conductor and earth being of adequate strength and capability for the intended purpose.
Electronic Alert System	An Electronic Interface for issuing/receiving Alerts.
Electronic Interface	A system, in accordance with the requirements of the SO's data system, at the Control Center, providing an electronic interface between the SO and a User, for issuing and receiving instructions, including Dispatch Instructions as provided for in the Grid Code and established pursuant to an agreement between the SO and the User.
Embedded Generator	Generating Units within a Power Station which are directly connected to a Distribution System or the system of any other User and has no direct Connection to the Transmission System.
Embedded HVDC	HVDC system connected within a Control Area.
Emergency	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit loss of transmission facilities or generation supply that could adversely affect the safety and security of the Transmission System
Emergency Assistance	The actions taken with respect to an Interconnector in case of Emergency in External System.
End Point of Startup Period	The time after which the rate of change of the Generating Unit output is not dependent upon the initial warmth of the Generating Unit.
Energize	The movement of any isolator, breaker or switch so as to enable active power and reactive power to be transferred to and from the Facility through the Generator's Plant and Apparatus and "Energized" and "Energizing", "Energization" shall be construed accordingly.
Energy	Electrical energy produced by Generation Plants or Generation Units, flowing through or supplied by Transmission Network or Distribution Network, measured in units of kilo watt hours (kWh) or multiples

Term	Definition
	thereof.
Energy Limit	The forecasted maximum amount of Energy that can be generated by an Energy Limited Generating Unit within a Schedule Day.
Energy Limited Generating Unit	A Generating Unit with a limit on the Energy it can deliver in a specified time period.
Energy Storage Generator (ESPP)	A site containing at least one ESU can automatically act upon a remote signal to change its Active Power output.
Energy Storage Unit (ESU)	A Generation Unit(s) using generic storage devices to generate and consume electricity such as BESS and Pumped Storage Hydro Plants.
Equipment	All machines, conductors, etc. used as part of, or in connection with, an electrical installation.
Event	An occurrence on, or relating to either the Transmission System or a User's System, including faults, incidents and breakdowns. These include: (a) Operations that form part of a planned outage which has been arranged in accordance with OC 4. (b) Events which cause plant or apparatus to operate beyond its rated design capability, and present a hazard to personnel. (c) Adverse weather conditions being experienced. (d) Failures of protection, control or communication equipment. (e) Risk of trip on apparatus or plant. This list is not exhaustive.
Excitation (System)	The Equipment providing the field current of Generating Unit, including all regulating and control elements, as well as field discharge or suppression Equipment and protective devices. The term “Excitation” shall be construed accordingly.
External Supply	An electrical supply source (diesel engine or any other) used to provide emergency electric power for Black Start capability in absence of supply from National Grid.
External System	A Power System that is connected to National Grid via an Interconnector.
Facility	The User's facility located at the Connection Site including the User's Plant and Apparatus plus the Plant and Apparatus to be installed at the User's side of the Connection Point necessary to effect the connection.
Fault	Any abnormal condition of the Power System that involves the electrical failure of the equipment, such as , transformers, generators, busbars, etc.
Fault Ride-Through Capability	The ability to stay Synchronized/ connected to the Power System during and following a Fault.
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

Term	Definition
	root of the mean sum of cubes of 12 individual measurements.
Flicker Severity (Long Term)	A measure of the visual severity of flicker derived from the time series output of flicker meter over a ten minute period and as such provides an indication of the risk of the User complaints.
Forbidden Zone	A MW range within which a Generator or Interconnector cannot operate in a stable manner due to an inherent technical limitation of the machine.
Forced Outage	An Outage of a Generating Unit or a Transmission facility due to a Fault or other reasons which has not been planned, also it results from emergency conditions directly associated with a component, requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed.
Forecast Minimum Generation Profile	The User's forecast of the average level of Minimum Generation, in MW, for the User's Plant for each Schedule Day
Forecast Minimum Output Profile	The User's forecast of the average level of minimum MW output, in MW, for each Schedule Day
Forecast Minimum Output Profile	The User's forecast of the average level of minimum MW output, in MW, for each Schedule Day
Formal Application	The process of application to be followed by User in accordance with CC 2.3.
Free Governor Response	The automatic adjustment of Active Power output by a Generation Unit, initiated by free governor action in response to continuous minor fluctuations of Frequency on the Power System.
Frequency Control	The retention of the frequency on the Transmission System within acceptable limits.
Frequency Limit Control	Operating mode of HVDC facilities in which Active Power output changes in response to change in System Frequency, in such a way that it assist with the recovery to the Target Frequency.
Frequency Regulation	The, mechanism through which the system's frequency is maintained within the allowable limits as specified in the Grid Code (OC 5) and NEPRA Performance Standards (Transmission)-Rules.
Frequency Response	The automatic adjustment of Active Power output from a Generator or Interconnector in response to Frequency changes.
Gas Turbine Unit	A Generating Unit driven by gas.
Generating Unit	One of the units of a Generator in a generating plant/station producing electric power and energy.
Generation	The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in mega watthours (MWh).
Generation and Transmission Outage Program (G&TOP)	The combined Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Generation and

Term	Definition
	Transmission System, as per OC4.
Generation Capacity	The amount of Generation Supply available in the system.
Generation Outage Program	Any or all of the Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Generators.
Generator	An entity who is involved in generation business under a Generation License granted by NEPRA.
Generator Performance Chart	A diagram which shows the MW and MVAR capability limits within which a Generator is expected to operate under steady-state conditions in the format set out in the Grid Code.
Generator Terminal Voltage	The voltage at stator terminals of a Generating Unit.
Generator Transformer	The main step-up transformer for a Generator through which power flows from the Generating Unit to the Transmission System.
Generator Work Unit	Auxiliary consumption of an individual Generating Unit of a Generator during maintenance/ Outage.
Global Load Forecast	Econometric Model (Regression Analysis) based consolidated system level forecast which is prepared by the System Operator and is used for the preparation of IGCEP and Long-term transmission plan.
Governor	A mechanical device used to automatically regulate the speed of a turbine of electric generator.
Governor Control System	A system which will result in Active Power output of a Generation Unit changing, in response to a change in System Frequency, in a direction which assists in the recovery to Target Frequency
Governor Droop	In relation to the operation of the governor of a Generating Unit, the percentage droop in system frequency which would cause the Generating Unit under free governor action to change its output from zero to full load.
Grid Code	This code prepared by the SO pursuant to section 23H of the Act, and approved by the NEPRA, as from time to time revised, amended, supplemented or replaced with the approval of or at the instance of the NEPRA.
Harmonic Distortion	The departure of a waveform from sinusoidal shape, that is caused by the addition of one or more harmonics to the fundamental, and is the square root of the sum of the squares of all harmonics expressed as a percentage of the magnitude of the fundamental.
High Voltage Ride Through Capability	Ability of an SWE Plant to stay connected to the system during the allowable over-voltage conditions.
Hot Cooling Time	The period of time, following De-Synchronization of a Generating Unit after which the Warmth State transfers from being hot to being warm.
Hot Standby	A condition of readiness to be able to synchronize and attain an instructed output in a specified time period that must be maintained

Term	Definition
	by Generator.
Hot Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time shorter than or equal to its submitted Hot Cooling Time.
Hydro Unit /Plant	A Generating Unit which generates electricity from the movement of water excluding Pumped Storage Generation.
Imminent Overloading	The condition when the loading of transmission lines or substation Equipment is above 100 percent up to 110 percent of the continuous rating.
Incidents	An event of external or internal origin, affecting equipment or the supply system, and which disturbs the normal operation of the System.
Independent Power Producer (IPP)	A private power generating company not owned/ controlled by any public sector organization but subject to Central Dispatch.
Indicative Outage Program	The Outage Program that the SO shall prepare for Year 3.
Instrument Transformer	A transformer intended to transmit an information signal to measuring instruments, meters and protective or control devices. The term "instrument transformer" encompasses both current transformer and voltage transformers.
Integrated System Plan	A plan that provides integrated road map based on generation cost and incremental transmission cost for the efficient development of the National Grid.
Intention Application	The process of application to be followed by User in accordance with CC 2.2.
Inter tripping Scheme	The tripping of circuit-breaker(s) by signals initiated from protection at a remote location independent of the state of the local protection.
Interconnector	An entity connected to another Power System.
Interconnector Ramp Rate	The maximum rate of increase or decrease of the power transferred, in either flow direction, by an Interconnector.
Interconnector Ramp-down Capability	The rate of decrease of an Interconnector. Ramp-down Capabilities apply over the bi-directional range from its Interconnector Registered Import Capacity to its Interconnector Registered Export Capacity.
Interconnector Ramp-up Capability	The rate of increase of an Interconnector. Ramp-up Capabilities apply over the bi-directional range from its Interconnector Registered Export Capacity to its Interconnector Registered Import Capacity.
Interconnector Registered Capacity	The maximum Capacity, in either flow direction, expressed in whole MW, that an Interconnector can deliver on a sustained basis, without accelerated loss of equipment life, at the Connection Point. This figure shall include transmission power losses for the Interconnector.
Interconnector Registered Export Capacity	The maximum Capacity, expressed in whole MW that an Interconnector may export (transfer energy from the Power System to a remote network) on a sustained basis, without accelerated loss of

Term	Definition
	equipment life, as registered.
Interconnector Registered Import Capacity	The maximum Capacity, expressed in whole MW that an Interconnector may import (transfer energy from a remote network into the Power System) on a sustained basis, without accelerated loss of equipment life, as registered.
Interconnector Transformer	A transformer whose principal function is to provide the interconnection between the Interconnector and the Network and to transform the Interconnector voltage to the Network voltage.
Investigation	Investigation carried out by the SO under OC11, and “Investigate” shall be construed accordingly.
Island/Islanding	A Generating Plant or a group of Generating Plants and its associated Demand, which is isolated from the rest of the Transmission System but is capable of generating and maintaining a stable Supply of power to the Customers within the isolated area.
License	A license issued for generation, transmission or distribution under the Act.
Licensee	A holder of a license
Load	The Active, Reactive or Apparent Power as the context requires to be generated, transmitted or distributed.
Load Curve	The curve that represents the behavior of the MW load during a particular study period.
Load Curves of Daily Peaks	The graphical representation of daily peak MWs of an electric power entity over a given study period.
Load Dispatch Center	The Control Center of System Operator.
Load Factor	The ratio between average Load over a given period to the peak Load occurring in that period.
Load Profile	Means configurable interval multi-channel data as specified time stamped stored in energy meter.
Load Up Break Point Cold	The break point which defines the shared MW boundary between the two Loading Rates Cold.
Load Up Break Point Hot	The break point which defines the shared MW boundary between the two Loading Rates Hot.
Load Up Break Point Warm	The break point which defines the shared MW boundary between the two Loading Rates Warm.
Loading Rate	The Loading Rate Cold, Loading Rate Hot or Loading Rate Warm as the case may be.
Loading Rate Cold	The rate at which a Generating Unit increases Output from Block Load to Minimum Generation when it is instructed to Cold Start.
Loading Rate Hot	The rate at which a Generating Unit Increases Output from Block Load to Minimum Generation when it is instructed to Hot Start.

Term	Definition
Loading Rate Warm	The rate at which a Generating Unit Increases Output from Block Load to Minimum Generation when it is instructed to Warm Start.
Loss of load probability (LOLP)	Loss of Load Probability, the percentage of time that the system capacity is inadequate to meet load demand.
Low Frequency Disconnection	The process, a part of load reduction or management, of load disconnection (manually or automatic) under low frequency system conditions.
Low Frequency Event	An event where the Transmission System Frequency deviates to a value below acceptable values.
Low Frequency Relay	An electrical measuring relay intended to operate when its characteristic quantity (Frequency) reaches the relay settings by decrease in Frequency.
Low Voltage Ride Through Capability	Ability of an SWE Plant to stay connected to the system during the allowable under-voltage conditions.
Maintenance Program	A set of schedules specifying planned maintenance for Equipment in the Transmission System or in any User System.
Maximum Charge Capacity	The maximum amount of Energy that can be produced from the storage of an Energy Storage Unit for a Schedule Day. E.g. BESS
Maximum Continuous Rating (MCR)	The normal Full Load MW Capacity of a Generator, which can be sustained on a continuous basis under specified conditions.
Maximum Demand	Maximum electrical power (MW and MVAR) used and registered in a specified time period.
Maximum Down Time	In the case of a Demand Side Unit, the maximum period of time during which Demand Side Unit MW Response can be greater than zero.
Maximum On Time	The maximum time that a Generating Unit/ Interconnector can run following Start Up.
Maximum Ramp Down Rate	The maximum Ramp Down Rate of a User. Mostly in MW per Minute.
Maximum Ramp Up Rate	The maximum Ramp Up Rate of a User. Mostly in MW per Minute.
Maximum Storage Capacity	The maximum amount of Energy that can be produced from the reservoir of a Pumped Storage Hydro for a Schedule Day.
Metering Data	Information on measured electrical quantities recorded in the meter register, such as energy, demand and power factor, including time and date.
Metering Point	means a Connection Point, equipped with a Metering System which is periodically read by an authorized Metering Service Provider
Metering Service Provider or MSP	means an entity as defined by NEPRA responsible for the organization, administration and maintenance of the Metering System and serves as the central aggregator of Metering Data; additionally performs the functions of meter reading and validation at Metering Points and transferring those values to the Market Operator

Term	Definition
Metering SOPs	The Standard Procedures (SOPs) developed by MSP for Meter Data Reading, Meter Data VEE, and for operation &, maintenance of the Metering System and MDM server..
Metering System	The system, established according to the requirements of the Grid Code, to measure and record the Energy injected into or withdrawn from the Transmission System by a User.
Minimum Charge Capacity	The minimum amount of Energy that must be produced from the storage of an Energy Storage Unit for a Schedule Day. E.g. BESS
Minimum Demand Regulation or MDR	Means minimum level of Active Power of a Generator, which is sufficient to provide an adequate regulating margin for necessary Frequency Control.
Minimum Down Time	In the case of Demand Side Units, the minimum period of time during which Demand Side Unit MW Response at a Demand Side Unit can be greater than zero.
Minimum Generation/Minimum Stable Level/Minimum Load	The minimum MW output, which a Generator can generate continuously, registered as a Technical Parameter.
Minimum Off Time	The minimum time that must elapse from the time of a Generating Unit De-synchronizes before it can be instructed to Start-up.
Minimum On Time	The minimum time that must elapse from the time of a Generating Unit Start-up before it can be instructed to Shut down.
Minimum Storage Capacity	The minimum amount of Energy that must be produced from Energy Storage Unit for a Schedule Day e.g. Pumped Storage Hydro
Minimum transmission voltage	Sixty-six kilovolts or such other voltage that the Authority may determine to be the minimum voltage al which electrical facilities are operated when used to deliver electric power in bulk.
Monitoring	Monitoring carried out by the SO under OC11, and “Monitor” shall be construed accordingly.
Multiple Outage Contingency	An Event caused by the failure of two or more Components of the Grid
National Grid	The Power System of Islamic Republic of Pakistan
National Grid Company	Means the person engaged in the transmission of electric power and granted a license under section 17.
NEPRA	The National Electric Power Regulatory Authority (NEPRA) established under Section 3 of the Regulation of Generation, Transmission and Distribution of Electric Power Act, 1997 to exclusively regulate the provision of electric power services in Pakistan.
NEPRA (Fees and Penalties) rules	The rules developed by the Authority in respect of the payment of fees by the licensees and the procedure for imposition and payment of fines and penalties levied by the Authority.
NEPRA Power Safety Code	Power safety code devised by NEPRA
Non-Disclosure Agreement	A non-disclosure agreement is a legally binding contract that establishes a confidential relationship. An NDA may also be referred to

Term	Definition
	as a confidentiality agreement.
Nominal or Nameplate Power	The rated power output specified by the manufacturer of a given electrical equipment.
Nominal System Voltage	As defined in NEPRA Rules on Performance Standards (Distribution) or other NEPRA applicable documents.
Nominal Voltage	The value of the voltage by which the electrical installation or part of the electrical installation is designated and identified.
Non-Synchronous Generators	Power Electronics-based Generators that are not Synchronous.
Notice to Synchronize	The amount of time (expressed in minutes) that is declared by a Generator in relation to a CDGU or Interconnector to enable it to be synchronized following the receipt of an Instruction from SO to synchronize with the System.
Notification	The daily submission Notice of Availability by Users to the System Operator for dispatch purposes.
Off-Site Storage Location	The site in close vicinity to the Generator Site where (pursuant to a lease, license or other agreement) the User stores stocks of Primary Fuel and/or Secondary Fuel. A dedicated pipeline with a dedicated pump must be in place on this site between the dedicated fuel tank off-site and the Generating Plant.
Open Access	Provision of connection and non-discriminatory "Use" of the transmission, sub-transmission and distribution network of a licensee.
Open Cycle Mode	The mode of operation of a CCGT Installation where only the Gas Turbine Unit is operational (i.e. without operation of any associated Steam Turbine Units).
Operating Characteristics/ Technical Parameters	The technical capabilities, flexibilities and limitations for the operation of a User as registered or declared in accordance with the provisions of the Grid Code.
Operating Criteria	Criteria of Operation explained in OC 6.
Operating Reserve	Sum of Primary, Secondary and Tertiary Operating Reserves as explained in OC 5.
Operation	A scheduled or planned action relating to the operation of a System (including an Embedded Generator).
Operational Data	Data required under the Operating Codes and/or Scheduling and Dispatch Codes.
Operational Date	Commissioning Date
Operational Effect	Any effect on the operation of the relevant other system that causes the Transmission System or the User's System 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. Operationally Effected shall be construed accordingly.

Term	Definition
Operational Phase	The Operational Phase follows on from the Pre-Operational Phase and covers the period 3 months ahead of Schedule Day.
Operational Planning	The procedure explained in OC4.
Operational Planning Horizons	Pre-Operational, Operational, Control and Post Control Phases.
Operational Tests	Tests carried out by the SO in order to maintain and develop operational procedures, to train staff and to acquire information in respect of Transmission System behavior under abnormal System conditions, and also tests carried out by other Users for similar purposes in respect of their Plant.
Operational Thermal Limit Capacity	The maximum loading capacity of Transmission facilities in Normal conditions.
Operations Report	An annual Report summarizing the occurrences of operation on the User or Transmission System.
Optimal Power Flow (OPF)	The best operating levels for electric Generators in order to meet demands given throughout a Transmission System, usually with the objective of minimizing Operating cost.
Other System	The External System
Outage	The state of a system, User or component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of service to customers, depending on system configuration.
Outage Notice	A Notice submitted by a User under OC4 notifying SO of an Outage.
Output	The actual output at the main terminals of a Generating Unit (in MW) derived from data measured pursuant to this Grid Code.
Partial Shutdown/Collapse	The situation existing when all generation has ceased in a particular part of the System and there is no electricity supply from Interconnectors or other parts of the System to that particular part of the Total System and, therefore, that particular part of the Total System is shutdown; with the result that it is not possible for that particular part of the Total System to begin to function again without directions relating to a Black Start or re-energization from healthy part.
Peak Demand	Maximum Demand
Peak Instruction	In the case of a Gas Turbine CDGU, an instruction requiring it to generate at a level in excess of its Availability but not exceeding its temperature adjusted peak capability
Penalty	A penalty, which may be imposed under the latest “NEPRA Fee and Fine Rules”.
Person	Shall include an association of persons, concern, company, firm or undertaking; authority, or body corporate set up or controlled by the Federal Government or, as the case may be, the Provincial Government.

Term	Definition
Planned Outage	An Outage of Equipment that is requested, negotiated, scheduled and confirmed a reasonable amount of time ahead of the maintenance or repairs taking place, as given in OC 4.
Plant and Apparatus	Fixed and movable equipment used in the generation and transmission of electricity.
Plant Factor	The ratio of the actual electrical energy produced to the possible maximum electrical energy that could be produced in any defined period.
Post Control Phase	The day following the Schedule Day.
Post Event Notice	A notice issued by the SO to a User in accordance with OC1
Power Factor	The ratio of Active Power to Apparent Power.
Power Line Carrier (PLC)	Communications system of radio frequency generally under 600 kHz, which transmits information using high voltage transmission lines.
Power Oscillation Damper	A supplementary control system that can be applied to existing devices like HVDC, STATCOM and Generators (in the form of PSS) to improve the damping of oscillations in the system which may initiate due to any reason.
Generator	An installation comprising one or more Generating Units owned and controlled by the same Generator.
Power Purchase Agreement (PPA)	An agreement to purchase power while using Transmission System.
Power Quality	Electric power quality is the degree to which the voltage, frequency, and waveform of a power supply system conform to established specifications.
Power Station Operation & Dispatch Agreement (PSODA)	A formal agreement for operation, control, dispatch, outage and maintenance procedures and requirements of the power station, with the SO.
Power System	An electricity supply system consisting of generation, transmission and distribution functions having an independent system operation and control.
Power System Restoration Plan	An Operational Plan developed under OC 12 for restoration of System after Partial or Total Shutdown.
Power System Stabilizer (PSS)	Equipment controlling the exciter output via the voltage regulator in such a way that power oscillations of the synchronous machines are dampened. Input variables may be speed, frequency or power (or a combination of these).
Pre-Operational phase	Pre-Operational phase covers Year 1 and Year 2.
Preventive Maintenance	The periodic maintenance performed on the equipment to avoid the occurrence of possible unplanned failure or outages.
Primary Control	Primary Frequency Control

Term	Definition
Primary Frequency Control	Primary frequency control enables a frequency response to maintain grid stability. This PFC frequency response algorithm replaces the tuning of regular droop speed controls, which are standard on any turbine: Maintains correct frequency for turbine/generator by adjusting the total MW output. This shall be taken as Fast Frequency control for invertor based generators.
Primary Fuel	The fuel or fuels registered in accordance with the Grid Code as the principal fuel(s) authorized for Energy production by the Generation Unit
Primary Fuel Registered Capacity	The Registered Capacity of Generating Unit running of Primary Fuel.
Primary Fuel Switchover Output	The MW output, not lower than Minimum Load at which a Generation Unit can achieve a switch over from Primary Fuel to Secondary Fuel.
Primary Meter	A device used to record electrical quantities such as energy, MDI etc. consumed by a USER along with time stamped events used for billing purpose.
Primary Metering System	A complete metering system installed at the Metering Point such as metering CT, VT, Meter, communication equipment and secondary circuits of instrument transformers including interconnecting cables; wires, metering cabinets and associated devices used for billing purpose
Priority Customers	Customers which are either: exempt from load shedding or exempt from load shedding under the technical under- frequency load shedding scheme or prioritized for supply under the technical under-frequency load shedding scheme.
Protection	The provisions for detecting abnormal conditions on a System and initiating fault clearance or actuating signals or indications.
Protection System/Scheme	The means (scheme or system) including the Apparatus used to detect, limit and remove Faults from the Power System.
Provincial Grid Company (PGC)	A person engaged in the transmission electric power and licensed under Section 18A of NEPRA Act within the territorial limits of such Province.
Provisional Outage Program	The Outage Program that the SO shall prepare for the period up to end of Year 2
Prudent Utility Practice/Prudent Industry Practice/Good Industry Practice	Those standards, practices, methods and procedures conforming to safety and legal requirements which are attained by exercising that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from skilled and experienced operatives engaged in the same type of undertaking under the same or

Term	Definition
	similar circumstances.
Q Control	A facility providing the means to automatically adjust the Reactive Power output of an HVDC System within a specified range.
Ramp Down Break Point	The MW level at which the Ramp Down Rate changes
Ramp Down Rate	The maximum rate of decrease in a Generating Unit's Output.
Ramp-up Rate	The maximum rate of increase in a Generating Unit's Output.
Rapid Voltage Change	A quick transition in root means square (r.m.s.) voltage occurring between two steady-state conditions, and during which the r.m.s. voltage does not exceed the dip/swell thresholds.
Reactive Compensation Equipment	An Equipment for production or absorption of Reactive Power to maintain Transmission System voltage within the specified limits.
Reactive Energy	Means the product of voltage, current, the sine of the phase angle between them and time, measured in units of VARh and standard multiples thereof.
Reactive Power	The product of voltage and current and the sine of the phase angle between them measured in units of VAR and standard multiples thereof.
Reactive Reserve	The MVAR reserve on the on-line Generators (difference between MVAR capability at the output MW level at a given time and actual MVAR produced).
Regional Grid Company (RGC)	A Person engaged in the transmission electric power and licensed under Section 18A of NEPRA Act within the territorial limits of such Region (for example K-Electric).
Registered Capacity	The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of generation, transmission, or other electrical equipment.
Registered Operating Characteristic	The values of Technical Parameters.
Remedial Actions	Those actions described in SDC2, which the Operator undertakes in case of emergency.
Remote Terminal Unit (RTU)	A part of the SCADA system. It is a set of electronic devices that collects and transmits data to, and receives and executes the commands from the master unit.
Renewable Electricity	Means electricity derived from (a) a wind, solar, renewable, biomass, ocean (including tidal, wave, current and thermal), geothermal or hydroelectric source; or (b) hydrogen derived from renewable biomass or water using an energy source described in clause (a);
Reserve	Operating Reserve
Reserve Margins	Excess generation which is available to meet the system demand if in

Term	Definition
	service generation is lost or demand exceeds the forecast.
Responsible Manager	A manager who has been duly authorized by a User or the SO to sign Site Responsibility Schedules on behalf of that User or the SO.
Responsible Operator	A person nominated by a User to be responsible for System control for its System.
Revenue Metering	Metering used to measure the demand and energy at a specific point in the system upon which an invoice will be prepared and payments shall be made between power supplier and User.
Review Panel	Grid Code Review Panel (GCRP)
Revision	means a comprehensive revision of, and replaces and supersedes, in its entirety, the existing Grid Code based on changes in power sector reforms, policies and technological changes recommended by Grid Code Review Panel and approved by the NEPRA.
Safety	Safety from the hazards arising from the live Equipment, Plant, or other facilities of the Transmission System (or User System).
Safety Codes/Rules	The rules that seek to safeguard personnel working on the Grid (or User System) from the hazards arising from the Equipment or the Transmission System (or User System).
Safety Coordinator	A Person or Persons nominated by SO and each User to be responsible for the co-ordination of Safety when work (which includes testing) is to be carried out on a System which necessitates the provision of Safety Precautions. “Coordination” to be construed accordingly.
Schedule Day	The period from 0000 hours in the Schedule Day until 0000 hours on the next following Day.
Scheduling	A process to determine which Unit or Equipment will be in operation and at what loading level and the term "Scheduled" and like terms shall be construed accordingly.
Secondary Fuel	The fuel or fuels registered in accordance with the Grid Code as the secondary or back-up fuel(s) authorized for Energy production by the Generating Unit.
Secondary Fuel Switchover Output	The MW output, not lower than Minimum Load at which a Generation Unit can achieve a switch over from Secondary Fuel to Primary Fuel.
Secondary Response	The Frequency Response as a result of Secondary Frequency Control.
Security Constrained Economic Dispatch (SCED)	The allocation of System Demand to individual generation facilities to effect the most economical production of electricity for optimum system economy, security and reliability with due consideration to Variable Operation Costs, incremental network losses, load flow considerations and other operational considerations as determined solely by the System Operator.
Service territory	The geographical area specified in a license within which the licensee is

Term	Definition
	authorized to conduct its business.
Shaving Mode	The Synchronized operation of Generation Unit(s) to the Distribution System at an Individual Demand Site of a Demand Side Unit where the Generation Unit(s) supplies part of the DNO Demand Customer's Load.
Short Circuit Ratio	It is the ratio of field current required to produce rated armature voltage at open circuit to the field current required to produce the rated armature current at short circuit
Short Term Maximization Capability	The capability of a Generating Unit to deliver, for a limited duration of time, MW Output greater than its Registered Capacity.
Short Term Maximization Capability	The capability of a Generating Unit to deliver, for a limited duration of time, MW Output greater than its Registered Capacity.
Short Term Maximization Time	The time that the Short-Term Maximization Capability could be maintained.
Short Term Planned Maintenance Outage or STPM Outage	An Outage designated as an STPM Outage, the duration of which shall not, unless SO in its absolute discretion agrees, exceed 72 hours but not including any overrun of such Outage.
Short-Circuit Current	The current flowing through electrical system during the occurrence of short circuit.
Significant Incident	An Event on the Transmission System, a Distribution System, or the System of any User that has a serious or widespread effect on the Grid, the Distribution System, and/or the User System.
Significant Incident Report	A report prepared after the occurrence of a Significant Incident pursuant to OC 8.
Single Line Diagram	Schematic representations 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) bus bars, overhead lines, underground. Cables, power transformers, and reactive compensation equipment. It shall also show where Generating Plant is connected, and the points at which Demand is supplied.
Site Common Drawings	Drawings prepared for each Connection Site which incorporate Connection Site layout drawings, electrical layout drawings, common protection/ control drawings and common service drawings.
Soak Time Cold	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Cold during a Cold Start.
Soak Time Hot	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Hot during a Hot Start.
Soak Time Trigger Point Cold	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Cold Start.
Soak Time Trigger Point Hot	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Hot

Term	Definition
	Start.
Soak Time Trigger Point Warm	A constant MW level at which a Generating Unit must remain while loading up between Block Load and Minimum Generation after a Warm Start.
Soak Time Warm	The duration of time for which the Generating Unit must remain at the Soak Time Trigger Point Warm during a Warm Start.
Spatial Load Forecast	Power Market Survey based forecast which is prepared by each Distribution Company and is used for Medium term Planning.
Special Action(s)	The action(s), as defined in Scheduling and Dispatch Code, that the SO may require a User to take in order to maintain the integrity of the System.
Special Protection Scheme	A control or protection scheme to facilitate System operation by the inter-tripping of circuit breakers or other Control Actions.
Special Purpose Transmission Licensee	A company licensed under Section 19 of NEPRA Act to engage in the construction, ownership, maintenance and operation of specified transmission facilities.
Standing Instruction	An Instruction for a specified action notified to a User in advance by SO whereby, when the specified circumstances arise, the User will take the specified action as though a valid Instruction had been issued by SO.
Start of Restricted Range (Forbidden Zone)	The start point in MW of a Forbidden Zone.
Start-Up	The action of bringing a Generator from shutdown to synchronous speed.
Start-up Cost	That element of the generation prices for a CDGU which relates to the start-up of the CDGU.
Station Transformer	A transformer supplying electrical power to the auxiliaries of a Generator, is not directly connected to the Generator terminals.
Steam Turbine	A Generation Unit whose prime mover converts the heat-energy in steam to mechanical energy.
Supplier	A person licensed under the NEPRA act with the assigned roles and responsibilities as mentioned in the section 23F of the Act.
Supply	The process of delivering electrical energy; also, the amount of electric energy delivered, usually expressed in mega-watthours (MWh).
Synchronize	The condition where an incoming Generating Unit or system/Interconnector is connected to another System so that the frequencies and phase relationships of that Generating Unit or System, as the case may be, and the System to which it is connected are identical and the terms “Synchronize”, “Synchronizing”, “Synchronized”, and “Synchronization” shall be construed accordingly.
Synchronizing Time	The time taken to bring a Generating Unit to a Synchronized state from

Term	Definition
	a De-Synchronized state.
Synchronizing Time Cold	The time taken to bring a Generating Unit to a Synchronized state from a Cold (De-Synchronized) state.
Synchronizing Time Hot	The time taken to bring a Generating Unit to a Synchronized state from a Hot (De-Synchronized) state.
Synchronizing Time Warm	The time taken to bring a Generating Unit to a Synchronized state from a Warm (De-Synchronized) state.
Synchronous Generating Unit	A Generating Unit composed of a synchronous alternator(s) coupled to a turbine and synchronously-connected to the Transmission System
Synchronous Compensation/Condenser	The operation of rotating synchronous Apparatus for the specific purpose of either the production or absorption of Reactive Power.
Synthetic Inertia	The controlled contribution of electrical torque from a unit that is proportional to the ROCOF at the terminals of the unit.
System Adequacy	Ability of the system at any instant to balance Power supply and demand
System Emergency Condition	A Partial Shutdown or Total Shutdown or any other physical or operational condition and/or occurrence on the Power System which, in the SO's opinion, is i imminently likely to endanger or is endangering life or property; or ii is imminently likely to impair or is impairing: iii (a) the SO's ability to discharge any statutory, regulatory or other legal obligation and/or (b) the safety and/or reliability of the Power System.
System Fault Dependability Index (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 - F1/A Where: A = Total number of system faults F 1 = Number of system faults where there was a failure to trip a circuit breaker.
System Frequency/ Frequency	The number of alternating current cycles per second (expressed in Hertz) at which a System is running.
System Integrity	Status of a Power system operating as a unique interconnected system.
System Operating Voltage	Operating Voltage limits as defined in OC 5
System Operator	A person licensed under the NEPRA act with the assigned roles and responsibilities as mentioned in the section 23G and 23H of the Act.
System Reliability	Ability of the system to fulfill Adequacy and Security
System Security	Ability of the system to withstand contingencies/changes and remain

Term	Definition
	in its secure state or operate within its acceptable limits.
System Stability	The ability of the dynamic components of the Power System to return to a normal or stable operating point after being subjected to some form of change or disturbance.
System Test	Tests which involve simulating conditions, or the controlled application of irregular, unusual or extreme conditions, on the System, or any part of the System, but which do not include Commissioning or recommissioning tests or any other tests of a minor nature.
Target Charge Level	Target Charge Level for BESS
Target Frequency	The Frequency determined by the SO, as the desired operating Frequency of the Power System.
Technical Parameters	The technical capabilities, flexibilities and limitations for the operation of a User as registered or declared in accordance with the provisions of the Grid Code.
Telemetering	A process in which measurements are made at some remote location and the results are transmitted through telecommunication facilities. The transmission of the values of measured variables using telecommunication techniques is also called telemetering.
Test Coordinator	The coordinator appointed by the SO pursuant to the provisions of the OC 10.
Test Proposer	The User submitting proposal for a test under OC10.
Testing	Testing carried out by the SO or User pursuant to OC 10,11 and/or CC and the term “Test” shall be construed accordingly.
Testing and Commissioning	Testing involved during the process of Commissioning.
Thermal Overload	A Thermal Overload occurs when the designed thermal rating of a transmission line or cable is exceeded. The thermal rating of a transmission line is dictated by its physical construction and varies with the ambient weather conditions, while the thermal rating of a transmission cable is dependent solely on its physical construction.
Thermal Generator	A Generating Units that transform thermal energy into electricity
Total Harmonic Distortion	The departure of a waveform from sinusoidal shape, that is caused by the addition of one or more harmonics to the fundamental, and is the square root of the sum of the squares of all harmonics expressed as a percentage of the magnitude of the fundamental.
Total Shutdown/Blackout/ Collapse	The situation existing when all generation of the system has ceased resulting in the: shutdown of the power system, that it is not possible for the power system to begin to function again without SO directions relating to a Black Start.
Transformer	A device that transfers electric energy from one alternating-current circuit to one or more other circuits, either increasing (stepping up) or reducing (stepping down) the voltage.

Term	Definition
Transmission Connected Consumer	Any BPC/User directly connected to the Transmission System, other than the Generator/Interconnector or Distribution Entities.
Transmission Constraint	A limitation on the use of transmission system due to lack of transmission capacity.
Transmission Facilities	Electrical facilities and equipment including electrical circuits, transformers and sub-stations operating at or above the minimum transmission voltage.
Transmission Network Operator	An entity, which owns, operates and maintains Transmission Facilities.
Transmission Outage Program	Any or all of the Indicative Outage Program, the Provisional Outage Program and the Committed Outage Program of Transmission System.
Transmission Station	A substation connected at 66 kV and above.
Transmission System	An electrical system consisting of Transmission Facilities connecting at 66 kV and above voltage level.
Turbine Controller	A turbine controller consists of a number of computers which continuously monitor the conditions and collect statistics on its operation. As the name implies, the controller also controls a large number of switches, hydraulic pumps, valves, and motors within the turbine
Turbine Speed Control	A turbine speed control is a response that regulates rotational speed in response to changing load conditions.
U Control	A facility providing the means to automatically adjust the Reactive Power output of an HVDC System in response to changes in Voltage at AC Busbar.
Under frequency protection/relay	System protection that disconnects User or Equipment when the frequency drops below a percentage of the nominal operating frequency.
Unit Load Controller	A device which regulates the generation level when the Generator is operating in Frequency Sensitive Mode to ensure (as far as possible) that it does not exceed or fall short of acceptable limits as set in the Grid Code OC 5 and NEPRA Performance Standards (Transmission)-Rules.
Unplanned Outage	Any Outage that cannot reasonably be SO as a STPM.
User	A term used to refer to the Code Participant or Person to whom the Sub-Code applies
User Development	A User seeking new connection or modification in its existing system.
User Facility	Fixed and movable equipment of User used in the generation and transmission of electricity.
User Site	A site owned (or occupied pursuant to a lease, license or other agreement) by a User in which there is a Connection Point.
User System	Any system owned or operated by a User comprising: (i) Generator; or

Term	Definition
	(ii) Electrical systems consisting (wholly or mainly) of electric facilities used for the transmission or distribution of electricity from Connection Points onwards. The User system includes any sub-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 transmission, distribution and delivery of electric power but does not include any part of the bulk power transmission system.
Variable Operating Cost	The variable cost of operation of a Generator or Interconnector.
Voltage	Voltage of relevant section of Transmission System - nominally 500kV, 220kV, 132kV, 66kV.
Voltage Control	The strategy used by the SO and Users to maintain the voltage of the System, or the User System within the limits prescribed in the Grid Code.
Voltage Dip	A short-duration reduction in Voltage on any or all phases due to a Fault Disturbance or other Significant Incident, resulting in Transmission System Voltages outside the ranges as specified in this Grid Code.
Voltage Unbalance	The ratio of the negative or zero sequence component to the positive sequence component. In simple terms, it is a voltage variation in a power system in which the voltage magnitudes or the phase angle differences between them are not equal
Warm Cooling Time	The period of time, which must be greater than that defined by the Hot Cooling Time, post De-Synchronization of a Generating Unit after which the Generating Unit's Warmth State transfers from being warm to cold.
Warm Start	Any Synchronization of a Generating Unit that has previously not been Synchronized for a period of time longer than its submitted Hot Cooling Time and shorter than or equal to its submitted Warm Cooling Time.
Warmth	The temperature related condition of a CDGU which changes according to the length of time since the CDGU was last De-Synchronized, expressed as various levels of warmth (dependent upon the design of the CDGU).
Warmth State	Either cold, warm or hot, as defined under the timeframes since last De-Synchronizations for Cold Start, Warm Start or Hot Start respectively.
Week Ahead	A week prior to the Schedule Day.
Wheelers	As per NEPRA Wheeling Regulations.
Wind Farms	A group of *wind turbines* in the same location used to produce electricity.
Year Ahead	A year prior to the Year for which the data is being provided.

Term	Definition
Zero Voltage Ride Through Capability	Ability of an SWE Plant to stay connected to the system during zero voltage condition.