KERALA STATE ELECTRICITY REGULATORY COMMISSION

NOTIFICATION

No.1426/CE/2018/KSERC Thiruvananthapuram, 30th July 2019

The Kerala State Electricity Regulatory Commission hereby publishes under sub-section (3) of Section 181 of the Electricity Act, 2003, (Central Act 36 of 2003) the following draft of the Kerala State Electricity Regulatory Commission (Kerala State Grid Code) Regulations, 2019, for information of persons likely to be affected thereby. Any objection or suggestions thereon may be forwarded to the Secretary, Kerala State Electricity Regulatory Commission, KPFC Bhavanam, C.V.Raman Pillai Road, Vellayambalam, Thiruvananthapuram- 695010 within one month from the date of publication of this notice. Objections and suggestions received on or before the said date shall be considered by the Commission before finalization of the said draft regulation.

By order of the Commission,

Secretary

Draft

CHAPTER I

PART I - GENERAL

1. **Short title, extent and commencement**.-

   (1) These Regulations shall be called ‘Kerala State Electricity Regulatory Commission (Kerala State Electricity Grid Code) Regulations, 2019’.

   (2) These Regulations shall extent to the whole State of Kerala.

   (3) These Regulations shall come into force from the date of publication of the same in the Official Gazette of the Government of Kerala.

2. **State Grid, Scope, Applicability, Requirements and Implementation**.-

   **(1) Kerala State Grid,**-

   a) Kerala State Power System operates in synchronism with Southern Regional Grid (S3). Southern Regional Grid System consists of power systems of the constituent States namely Andhra Pradesh, Telangana, Karnataka, Tamil Nadu, Kerala and the Union Territory of Pondicherry, Inter State Generating Stations of NTPC Limited, NHPC Limited, Nuclear Power Corporation of India Limited (NPCIL), NLC India Limited etc. and the Inter State Transmission System including that of Power Grid Corporation of India Limited (PGCIL/ Powergrid).

   b) Electrical Grid of Kerala State (State Grid) have Generating stations of Kerala State Electricity Board Limited (KSEBL), Independent Power Producers (IPPs), Captive Power Stations, State Transmission System of KSEBL (STU), the distribution network of Distribution Licensees connected to the State Transmission System at various inter connection points on 66 kV, 33 kV and 11 kV, Transmission system of Power Grid located within the state of Kerala and connected at various points to the State Transmission System.

   c) The latest position of installed capacity of Generating Stations, details of 400 kV, 220 kV, 110 kV & 66 kV transmission lines and list of EHV Substations (substations of voltage exceeding 33 kV) in the State of Kerala are shown on the websites of the respective utilities/ entities and can be downloaded by interested Users.

   d) The single line diagram of 400/ 220/ 110/ 66 kV electrical transmission network of Kerala shall be made available by STU on KSEBL website i.e. ‘www.kseb.in’ which can be referred to by the users. A web link shall also be provided on SLDC website ‘www.sldckerala.org’ to have access to the single line diagram of STU network.
(2) **Scope, Applicability, Implementation and Operation of the State Grid Code,**-

a) These Regulations shall apply to all the Transmission & distribution licensees, Generators, Consumers including Captive, Open Access and Bulk, the STU/ SLDC and all other concerned users using the Kerala State Grid in the matter of Connectivity, Scheduling, Operation, Safety, Shutdown, Protection, Communication, Metering, Energy Accounting etc.

b) The STU/ SLDC and all other concerned users using the Kerala State Grid shall commence implementation of the provisions in this State Grid Code 2019, from the date of its publication in the official gazette of the Kerala Government.

c) The connectivity criteria and other provisions of the State Grid Code shall be applicable to the new Connections and equipments provided for new works/ replacements, from the date this State Grid Code is made effective.

d) The existing connections and equipments shall continue to operate till such time the State Grid Code Review Committee (SGCRC) considers alterations if necessary. However, operational aspects of the State Grid Code shall have no such relaxation and shall apply with immediate effect.

e) The State Grid Code shall apply to all the Users, SLDC, STU and any future Transmission licensee. The STU/ SLDC have the responsibility of implementing the State Grid Code.

f) It is the duty of SLDC, STU and all the Users to comply with KSGC. Users must provide the STU reasonable rights of access; service and facilities necessary to discharge its responsibilities in the User’s premises and to comply with instructions as issued by STU/ SLDC reasonably required to implement and enforce the State Grid Code.

g) SLDC shall not unduly discriminate against or unduly prefer any one or any group of persons; or STU in the conduct of any business.

h) The operation of the State Grid Code will be reviewed regularly by the State Grid Code Review Committee in accordance with the provisions of the relevant sections of the State Grid Code.

(3) **State Grid Code Requirements and Responsibilities,**-

a) The State Grid Code contains procedures to permit equitable management of day-to-day technical situations in the power system, taking into account a wide range of operational conditions likely to be
encountered under both normal and abnormal circumstances. It is nevertheless necessary to recognize that the State Grid Code cannot predict and address all possible operational conditions.

b) Users must therefore understand and accept that SLDC/ STU in such unforeseen circumstances may be required to act decisively to discharge its obligations under the Act, Regulations and/or its License. User(s) shall comply with the directions of SLDC/ STU in such circumstances and grievances, if any, may be brought before the Commission directly or through SGCRC.

c) In discharging its duties under the State Grid Code, STU and/or SLDC have to rely on information which Users shall supply regarding their requirements.

d) SLDC/ STU shall not be held responsible for any consequences that arise from its reasonable and prudent actions on the basis of the above actions.

(4) Confidentiality,-

Except as provided hereinafter, SLDC/ STU shall not, other than as required by the State Grid Code, disclose the information received from the users to any person without the prior written consent of the provider of the information;

Provided that this provision will not apply in respect of information in public domain;

Provided further that this provision shall not apply in respect of such information sought by Statutory authorities specified in Electricity Act or any other Act, Competent Courts, State Government or Central Government, Committee constituted by any of them and ordered to be supplied under RTI Act.

(5) Dispute Settlement Procedures,-

a) If any dispute arises with reference to the quality of electricity or safe, secure and integrated operation of the State Grid or in relation to any direction given under clause (7) below; it shall be referred to the Commission for a decision.

Provided that, pending the decision of the Commission, the directions of SLDC shall be complied with by the Users.
b) In the event of any dispute regarding interpretation of any provision of the State Grid Code between any User and SLDC/ STU, the matter may be referred to the SGCRC for its decision. The SGCRC’s decision shall be final and binding. During the intervening period, interpretation of SLDC/ STU shall apply unless otherwise directed by SGCRC.

c) In the event of any conflict between any provision of the State Grid Code and any contract or agreement between STU and Users or between Users, the provision(s) of the State Grid Code will prevail.

(6) Communication between STU and Users,-

a) All Communications between SLDC/ STU and Users shall be in accordance with the provisions of the relevant sections of the State Grid Code and shall be made to the designated Nodal Officer appointed by SLDC/ STU.

b) Unless otherwise specifically required by the State Grid Code all Communications shall be in writing, provided that circumstances wherein operation time scales require oral Communication, such Communications shall be confirmed in writing as soon as practicable.

c) In the case of oral Communication, the voice shall be recorded at SLDC and such record shall be preserved for a reasonable time to be decided by the State Grid Code Review Committee.

(7) Directives,-

a) SLDC may give directions and exercise such supervision and control as may be required for ensuring the integrated grid operation and for achieving the maximum economy and efficiency in the operation of the power system in the State under Section 33(1) of the Act and every user shall comply with the same.

b) Regional Load Despatch Centre may issue directions under Section 29 of the Electricity Act and the State Government may issue directives in certain matters under Section 37 of the Act and SLDC shall promptly inform the Commission and all Users of the requirement of such directives.

c) Directives issued by the Commission from time to time shall be complied by STU and all users.
(8) **Compatibility with Indian Electricity Grid Code,**

This State Grid Code is consistent/ compatible with the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 (IEGC), as amended from time to time. However, in matters relating to interstate transmission, if any provisions of the State Grid Code are inconsistent with the provisions of the IEGC, then the provisions of IEGC shall prevail.

(9) **Acronyms and Abbreviations,**

The following Acronyms and Abbreviations are used in this code:

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
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<tbody>
<tr>
<td>A</td>
<td>Ampere</td>
</tr>
<tr>
<td>AAAC</td>
<td>All Aluminium Alloy Conductor</td>
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<tr>
<td>ABCB</td>
<td>Air Break Circuit Breaker</td>
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<tr>
<td>ABT</td>
<td>Availability Based Tariff</td>
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<tr>
<td>AC</td>
<td>Alternating Current</td>
</tr>
<tr>
<td>ACSR</td>
<td>Aluminium Conductor Steel Reinforced</td>
</tr>
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<td>ADMS</td>
<td>Automatic Demand Management System</td>
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<td>AIS</td>
<td>Air Insulated Substation</td>
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<tr>
<td>ANERT</td>
<td>Agency for Non-conventional Energy and Rural Technology, Kerala</td>
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<td>ANSI</td>
<td>American National Standards Institute</td>
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<tr>
<td>APM</td>
<td>Administered Pricing Mechanism</td>
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<td>ATC</td>
<td>Available Transfer Capability</td>
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<td>AVR</td>
<td>Automatic Voltage Regulator</td>
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<tr>
<td>BIS</td>
<td>Bureau of Indian Standards</td>
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<td>BSLDC</td>
<td>Backup State Load Despatch Centre</td>
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<tr>
<td>CBIP</td>
<td>Central Board of Irrigation and Power, GOI.</td>
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<tr>
<td>CCGT</td>
<td>Combined Cycle Gas Turbine</td>
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<tr>
<td>CEA</td>
<td>Central Electricity Authority</td>
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<td>CERC</td>
<td>Central Electricity Regulatory Commission</td>
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<td>CGP</td>
<td>Central Generating Plant</td>
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<td>CMRI</td>
<td>Common Meter Reading Instrument</td>
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<td>COSEM</td>
<td>Companion Specification for Energy Metering</td>
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<td>CPP</td>
<td>Captive Power Plant</td>
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<td>CT</td>
<td>Current Transformer</td>
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<td>CTU</td>
<td>Central Transmission Utility</td>
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<td>CVT</td>
<td>Capacitive Voltage Transformer</td>
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<td>DAS</td>
<td>Data Acquisition System</td>
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<td>DCC</td>
<td>Distribution Control Center</td>
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<td>D/C</td>
<td>Double Circuit</td>
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<tr>
<td>DLMS</td>
<td>Device Language Message Specification protocol</td>
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<td>DR</td>
<td>Disturbance Recorder</td>
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<td>DISCOMs</td>
<td>Distribution Companies</td>
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<td>Description</td>
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<td>DSM</td>
<td>Deviation Settlement Mechanism</td>
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<td>Energy Management Centre, Kerala</td>
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<td>EFR</td>
<td>Earth Fault Relay</td>
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<td>EHT</td>
<td>Extra High Tension</td>
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<td>EHV</td>
<td>Extra High Voltage equal to and greater than 66 kV</td>
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<td>EMPT</td>
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<td>Electro Magnetic Transient Programme</td>
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<td>EPS</td>
<td>Electric Power Survey of GOI</td>
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<td>FACTS</td>
<td>Flexible AC Transmission System</td>
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<td>FL</td>
<td>Fault Locator</td>
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<td>FRC</td>
<td>Frequency Response Characteristics</td>
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<td>FRT</td>
<td>Fault Ride Through</td>
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<td>GIL</td>
<td>Gas Insulated Lines</td>
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<td>GOI</td>
<td>Government of India</td>
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<td>GOK</td>
<td>Government of Kerala</td>
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<td>Geographical Positioning System</td>
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<td>High Speed Auto Reclosure</td>
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<td>HV</td>
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<td>High Temperature Low Sag conductor</td>
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<td>ICT</td>
<td>Inter Connecting power Transformer</td>
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<td>IDMT</td>
<td>Inverse Definite Minimum Time (relay)</td>
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<td>IEC</td>
<td>International Electro-Technical Commission</td>
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<td>IEC Standard</td>
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<td>IED</td>
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<td>IEEE</td>
<td>Institution of Electrical and Electronic Engineers Inc. USA</td>
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<td>IEGC</td>
<td>Indian Electricity Grid Code</td>
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<td>IEM</td>
<td>Interface Energy Meter</td>
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<td>IPP</td>
<td>Independent Power Producer</td>
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<td>Indian Standards</td>
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<td>ISGS</td>
<td>Inter State Generating Station</td>
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<td>IT</td>
<td>Information Technology</td>
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<tr>
<td>kV</td>
<td>Kilo Volt</td>
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<td>kVA</td>
<td>Kilo Volt Ampere</td>
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<td>kVAr</td>
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<td>kVArh</td>
<td>Kilo Volt Ampere Reactive Hour</td>
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<td>kWh</td>
<td>Kilo Watt Hour</td>
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<td>KSGC</td>
<td>Kerala State Electricity Grid Code</td>
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<td>LBB</td>
<td>Local Breaker Backup</td>
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<td>LCP</td>
<td>Line Clear Permit</td>
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<td>LCR</td>
<td>Line Clear Return</td>
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<td>Abbreviation</td>
<td>Meaning</td>
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<td>LTA</td>
<td>Long Term Open Access</td>
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<td>LGBR</td>
<td>Load Generation Balance Report</td>
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<td>LVRT</td>
<td>Low Voltage Ride Through</td>
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<td>MCR</td>
<td>Maximum Continuous Rating</td>
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<td>MNRE</td>
<td>Ministry of New and Renewable Energy Sources</td>
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<td>MOCB</td>
<td>Minimum Oil Circuit Breaker</td>
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<td>MPP</td>
<td>Mega Power Project</td>
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<td>MU</td>
<td>Million Unit</td>
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<td>MVA</td>
<td>Mega Volt Ampere</td>
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<td>MVAh</td>
<td>Mega Volt Ampere Hour</td>
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<td>MVAR</td>
<td>Mega Volt Ampere Reactive</td>
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<td>MVARh</td>
<td>Mega Volt Ampere Reactive Hour</td>
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<td>MW</td>
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<td>MWh</td>
<td>Mega Watt Hour</td>
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<td>MTOA</td>
<td>Medium Term Open Access</td>
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<td>NABL</td>
<td>National Accreditation Board for Testing and Calibration Laboratories, GOI</td>
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<td>NHPC</td>
<td>National Hydro Power Corporation</td>
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<td>NLDC</td>
<td>National Load Despatch Centre</td>
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<td>NPCL</td>
<td>Nuclear Power Corporation Limited</td>
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<td>NTPC</td>
<td>National Thermal Power Corporation</td>
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<td>Open Access</td>
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<td>OCR</td>
<td>Over Current Relay</td>
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<td>OLTC</td>
<td>On Load Tap Changer</td>
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<td>OPGW</td>
<td>Optical Ground Wire</td>
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<td>PD</td>
<td>Planning Data</td>
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<td>PDC</td>
<td>Phasor Data Concentrator</td>
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<td>PGCIL</td>
<td>Power Grid Corporation of India Limited</td>
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<td>PIR</td>
<td>Passive Infrared Sensor/ Pre Insertion Resistors</td>
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<td>PLCC</td>
<td>Power Line Carrier Communication</td>
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<td>Plant Load Factor</td>
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<td>PMU</td>
<td>Phasor Measurement Unit</td>
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<td>Power Purchase Agreement</td>
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<td>Pressure Release Valve</td>
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<td>PTW/PWR</td>
<td>Permit To Work/ Permit To Work Return</td>
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<td>P&lt;sub&gt;Max&lt;/sub&gt;</td>
<td>Maximum Active Power</td>
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<tr>
<td>Q&lt;sub&gt;Max&lt;/sub&gt;</td>
<td>Maximum Reactive Power supplied i.e. lagging</td>
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<td>Q&lt;sub&gt;Min&lt;/sub&gt;</td>
<td>Maximum Reactive Power absorbed i.e. leading</td>
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<td>P,Q</td>
<td>P-Active Power, Q – Reactive Power</td>
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<td>PT</td>
<td>Potential Transformer</td>
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<td>PTCC</td>
<td>Power and Telecommunication Co-ordination Committee</td>
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<td>pu</td>
<td>per unit</td>
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<td>power factor</td>
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<td>REA</td>
<td>Regional Energy Account</td>
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<td>REF</td>
<td>Restricted Earth Fault</td>
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<td>RLDC</td>
<td>Regional Load Despatch Centre</td>
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<td>Abbreviation</td>
<td>Full Form</td>
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<td>RLNG</td>
<td>Re-liquefied Natural Gas</td>
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<td>RPC</td>
<td>Regional Power Committee</td>
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<td>RRF</td>
<td>Renewable Regulatory Fund</td>
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<td>RES</td>
<td>Renewable Energy Source</td>
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<td>RTDS</td>
<td>Real Time Digital Power System Simulator</td>
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<td>SAS</td>
<td>Substation Automation System</td>
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<td>SAMAST</td>
<td>System of Accounting, Metering and Settlement of Transactions in electricity</td>
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<td>S/C</td>
<td>Single Circuit</td>
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<td>SCADA</td>
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<td>SEA</td>
<td>State Energy Account</td>
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<td>SF6</td>
<td>Sulphur Hexa Fluoride</td>
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<td>Surge Impedance Loading</td>
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<td>SGS</td>
<td>State Generating Station (Intra)</td>
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<td>SOCC</td>
<td>State Operation Coordination Committee</td>
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<td>SPS</td>
<td>Special Protection Scheme</td>
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<td>SRS</td>
<td>Site Responsibility Schedule</td>
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<td>STS</td>
<td>State Transmission System (Intra)</td>
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<td>STDA</td>
<td>State Transmission Deviation Account</td>
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<td>STOA</td>
<td>Short Term Open Access</td>
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<td>STU</td>
<td>State Transmission Utility</td>
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<td>SVC</td>
<td>Static VAR Compensator</td>
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<td>SLDC</td>
<td>State Load Despatch Centre</td>
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<td>SRLDC</td>
<td>Southern Regional Load Despatch Centre</td>
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<td>SRPC</td>
<td>Southern Regional Power Committee</td>
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<td>SBU</td>
<td>Strategic Business Unit</td>
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<td>Technical Coordination Committee</td>
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<td>ToD</td>
<td>Time of the Day</td>
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<td>TOV</td>
<td>Temporary Over Voltage</td>
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<td>TRM</td>
<td>Transmission Reliability Margin</td>
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<td>TTC</td>
<td>Total Transfer Capability</td>
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<tr>
<td>TSE</td>
<td>Time Synchronizing Equipment</td>
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<td>THD</td>
<td>Total Harmonic Distortion</td>
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<tr>
<td>UI</td>
<td>Unscheduled Interchange</td>
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<td>UMPP</td>
<td>Ultra Mega Power Project</td>
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<td>VAR</td>
<td>Volt Ampere Reactive</td>
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<td>VCS</td>
<td>Video Conference System</td>
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<td>VOLL</td>
<td>Value of Lost Load</td>
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<td>VT</td>
<td>Voltage Transformer</td>
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<td>VSAT</td>
<td>Very Small Aperture Terminal</td>
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<td>WAMS</td>
<td>Wide Area Measurement System</td>
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<td>WEG</td>
<td>Wind Energy Generator</td>
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<td>Wh</td>
<td>Watt hour</td>
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3. **Definitions.-**

(1) In this Code unless the context otherwise requires,-

1) “**Act**” means the Electricity Act, 2003 (Central Act 36 of 2003), as amended from time to time;

2) “**Active Power**” means the product of voltage and the inphase component of alternating current measured in units of watts and standard multiples thereof;

3) “**Ancillary Services**” means in relation to power system (or grid) operation, the services necessary to support the power system (or grid) operation in maintaining power quality, reliability and security of the grid, such as but not limited to active power support for load following, reactive power support, black start etc.;

4) “**Automatic Voltage Regulator (AVR)**” means a continuously acting automatic excitation control system to control the voltage measured at the generator terminals of a Generating Unit;

5) “**Auxiliaries**” refers to all the plant and machinery required for the functional operations of the generating station/ transmission substation, that do not form part of the generating unit/ substation;

6) “**Backing Down**” means reduction of generation by a generating unit on instructions from State Load Despatch Centre/ Southern Region Load Despatch Centre;

7) “**Backup Load Despatch Centre (BSLDC)**” means the centre as established by the STU as redundant/ standby centre, to carry out the functions of SLDC for controlling system operation, in the absence of the functioning of SLDC;

8) “**Beneficiary**” means a licensee who has a share in an Inter State Generating Station (ISGS) and/or Intra State Generating Station (SGS);

9) “**Bilateral Transaction**” means a transaction for exchange of energy (MWh) between a specified buyer and a specified seller, directly or through a trading licensee or Power Exchange from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for a specified period;

10) “**Black Start Procedure**” means the procedure to recover the grid from partial or total blackout in the State;

11) “**BIS**” means the Bureau of Indian Standards;

12) “**Bulk Consumer**” means any consumer who avails supply at voltage of 66 kV or above;

13) “**Capacitor**” means an electrical facility provided for generation of reactive power;
14) “Captive Power Plant” (CPP) means a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such co-operative society or association and meeting the qualifying criteria detailed in Rule 3 of the Electricity Rules, 2005;
15) “CEA” or ‘Authority’ means the Central Electricity Authority of India;
16) “CERC” means the Central Electricity Regulatory Commission;
17) “Central Generating Station (CGS)” means the generating station owned by the companies that are owned or controlled by the Central Government;
18) “Central Transmission Utility (CTU)” means any Government Company which the Central Government may so notify under sub-section (1) of Section 38 of the Act;
19) “Collective Transaction” means a set of transactions discovered in Power Exchange through anonymous, simultaneous competitive bidding by buyers and sellers;
20) “Commission” or ‘KSERC’ means the Kerala State Electricity Regulatory Commission;
21) “Congestion” means a situation where the demand for transmission capacity exceeds the Available Transmission Capability;
22) “Communication Channel” means a dedicated virtual path configured from one user’s node to another user’s node, either directly or through intermediary node(s) to facilitate voice, video and data communication and tele protection system;
23) “Communication System” is a collection of individual communication networks, communication media, relaying stations, tributary stations, terminal equipments usually capable of inter connection and inter operation to form an integrated communication backbone for power sector. It also includes existing communication system of ISTS, STS, Satellite and Radio communication system and their auxiliary power supply system etc. used for regulation of interstate and intra state transmission of electricity;
24) “Connection Agreement” means an Agreement between STU, Intra State transmission licensee(s) other than STU (if any) and any person setting out the terms relating to a connection to and/or use of the Intra-State Transmission System;
25) “Connection Point” means a point at which a plant (generating station or a substation or bulk consumer) and associated equipment connects to the Transmission System;
26) “Connectivity” means the state of getting connected to the Intra State transmission system by a generating station, including a captive generating plant, a bulk consumer or Intra State transmission licensee;
27) “Control Area” means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas whenever required to do so and contributes to frequency regulation of the synchronously operating system;

28) “Control person” means a person identified as having technical capability and responsibility for cross boundary safety under Part VIII of this Grid Code;

29) “Data” means a set of values of analog or digital signal including a text, voice, video, tele-protection, alarm, control signal, phasor, status of device, weather parameter, parameter of a machine or the power system, market related data, clearing house information etc.;

30) “Data Acquisition System (DAS)” means a system provided to record the sequence of operations in real time, of the relays/ equipment as well as the measurement of pre selected system parameters;

31) “Date of Commercial Operation or COD” means the commercial operation date as provided in Part XI of this State Grid Code;

32) “Demand” means the demand of Active Power in MW and Reactive Power in MVAR of electricity;

33) “Despatch Schedule” means the ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time;

34) “Deviation Settlement” means the settlement of deviations from schedule in accordance with; Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related matters) Regulations 2014/ KSERC (Deviation Settlement Mechanism and related matters) Regulations, as amended from time to time;

35) “Disturbance Recorder (DR)” means a device provided to record the behavior of the preselected digital and analog values of the system parameters during an event (including a few cycles of pre fault condition);

36) “Drawal Schedule” means the summation of the station wise ex-power plant drawal schedules from all Inter State Generating Station (ISGS) and Intra State Generating Station (SGS) and drawal from/ injection to the Distribution Licensees (State grid) consequent to long term, medium term and short term open access transactions;

37) “Deviation” in a time block for a seller means its total actual injection minus its total scheduled generation and for a buyer means its total actual drawal minus its total scheduled drawal;

38) “Entitlement” means a share of a beneficiary (in MW/ MWh) in the installed capacity/ output capability of an Inter State Generating Station (ISGS) and/ or Intra State Generating Station (SGS), power contracted through contracts, power exchanges etc., as the case may be;
39) “Entity” means the ‘person’ who is in the control area of SLDC and whose metering and energy accounting is done within the state;

40) “Event” means an unscheduled or unplanned occurrence on the Grid including faults, incidents and breakdowns;

41) “Event Logging Facilities” means a device provided to record the chronological sequence of operation, of the relays and other equipments;

42) “Ex-Power Plant Schedule” means net MW (limited to one decimal point) output of a generating station, after deducting auxiliary consumption and transformation losses within the generating station;

43) “Extra High Voltage” (EHV) means where the voltage equals or exceeds 66,000 Volts under normal conditions;

44) “Fault Locator (FL)” means a device provided at the end of a transmission line to measure/indicate the distance at which a line fault may have occurred;

45) “Flexible Alternating Current Transmission System (FACTS)” means power electronics based system and other static equipment that provide a control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability;

46) “Force Majeure” means any event which is beyond the control of the persons involved which they could not foresee or with a reasonable amount of diligence could not have foreseen or which could not be prevented and which substantially affects the performance by a person such as the following including but not limited to:-
   a) Acts of God, natural phenomena, floods, droughts, earthquakes and epidemics;
   b) Enemy acts of any Government, domestic or foreign, war declared or undeclared, hostilities, priorities, quarantines, embargoes;
   c) Riot or Civil Commotion;
   d) Grid’s failure not attributable to the person.

47) “Forced Outage” means an outage of a Generating Unit or a Transmission facility due to a fault or other reasons which has not been planned;

48) “Gaming” in relation to these Regulations, shall mean an intentional mis-declaration of declared capacity by any generating station or seller or by a licensee or consumer or prosumer in scheduling and drawing power from various sources, in order to make an undue commercial gain;

49) “Generating Company” means any company or body corporate or association or body of individuals, whether incorporated or not or artificial juridical person, which owns or operates or maintains a generating station;

50) “Generation Schedule” means a dispatch schedule of a generating Station;
51) “Generating Unit” means an electrical Generating Unit coupled to a Turbine within a Power Station together with all Plants and Apparatus at that Power Station which relates exclusively to the operation of that generator;

52) “Good Utility Practices” mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period which could have been expected to accomplish the desired results at reasonable cost consistent with good business practices, safety and reliability;

53) “Governor Droop” means in relation to the operation of the governor of a Generating Unit, the percentage drop in system frequency which would cause the Generating Unit under free governor action to change its output from zero to full load;

54) “Grid Standards” means the standards specified by the Authority (CEA) under clause (d) of Section 73 of the Act;

55) “Independent Power Producer (IPP)” means a generating company not owned/ controlled by the Central/ State Government;

56) “Indian Electricity Grid Code (IEGC)” means the Regulations specified by the CERC in exercise of powers under clause (h) of subsection (1) of Section 79, read with clause (g) of sub section (2) of Section 178 of the Act;

57) “Interconnection Point (IP)” means a point on the grid, including a substation or a switchyard, where the interconnection is established between the facility of the user and the grid and where electricity injected into or drawn from the grid can be measured unambiguously for the user;

58) “Inter Connecting Transformers (ICTs)” means Power Transformers connecting different voltages at transmission level (i.e. 66kV and above);

59) “Inter State Generating Station (ISGS)” means a Central generating station or other generating station, in which two or more states have shares or have contracts to buy power;

60) “Inter State Transmission System (ISTS)” includes any system for the conveyance of electricity by means of a main transmission line from the territory of one State to another State:

   (i) The conveyance of electricity across the territory of an intervening State as well as conveyance within the State which is incidental to such interstate transmission of energy;

   (ii) The transmission of electricity within the territory of the State on a system built, owned, operated, maintained or controlled by CTU;

61) “Intra State Generating Station (SGS)” means a Generating station located within the geographical area of the State of Kerala, other than ISGS and connected to intra state transmission system;
62) “Intra State Transmission System (STS)” means a system of Transmission Lines and substations of voltage level 66 kV and above within the territory of the State of Kerala, built, owned, operated and maintained or controlled by the STU or a transmission licensee for conveyance of electricity;
63) “Inverter” means a device that changes direct current power into alternating current power;
64) “Kerala State Electricity Grid Code (KSGC)” means the Regulations specifying the philosophy and the responsibilities for planning, developing and operation of the Power System of the State of Kerala;
65) “Kerala Electricity Supply Code (KESC) or Supply Code” means the Regulations specifying the philosophy and the responsibilities for planning, developing and operation of the Distribution System in the State of Kerala;
66) “Lean Period” refers to that period in a day/ Month/ Year when the electrical power demand is low;
67) “Licensee” means a person who has been granted a license under Section 14 of the Act;
68) “Light Load” means the simultaneous minimum demand of the system being studied under specific time duration (e.g. annual, monthly, daily etc);
69) “Load” means the MW/ MWh/ MVAR/ MVARh consumed by a utility/ Installation;
70) “Long Term Access” means the right to use the intra State transmission and distribution system for a period exceeding 7 years;
71) “Long Term customer” means a person who has been granted long term access in the State;
72) “Main Protection” means the protection equipment or system expected to have priority in initiating either a fault clearance or an action to terminate an abnormal condition in the power system;
73) “Maximum Continuous Rating (MCR)” means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters;
74) “Medium Term Open Access” means the right to use intra- State transmission and distribution system from any generating station for a period equal to or exceeding three months but not exceeding five years;
75) “Medium Term customer” means a person who has been granted a medium term open access;
76) “Meter” means a device suitable for measuring, indicating and recording consumption of electricity or any other quantity related with electrical system and shall include, wherever applicable, other equipment such as Current Transformers (CT), Voltage Transformers (VT) or Capacitor Voltage Transformer (CVT) with necessary wiring and accessories;
77) “National Grid” means the entire interconnected electric power network of the country;
78) “Net Drawal Schedule” means the drawal schedule of a Distribution Licensee after deducting the apportioned transmission losses (estimated);
79) “NLDC” means the National Load Despatch Centre established under sub-section (1) of Section 26 of the Act;
80) “Open Access” means the non-discriminatory provision for the use of transmission lines or distribution system or associated facility with such lines or system by any licensee or consumer or a person engaged in generation in accordance with the regulations specified by the Commission;
81) “Operation” means a scheduled or planned action relating to the operation of a System;
82) “Operation Coordination Sub Committee (OCC)” means a sub-committee of SRPC with members from the state/regional entities which decide the operational aspects of the State/Regional Grid;
83) “Operating range” means the operating range of frequency and voltage as specified under the Operating Code;
84) “Outage” means a total or partial reduction in availability due to repair and maintenance of the transmission or distribution or generation facility or defects in the auxiliary system;
85) “Partial Grid Disturbances” means a shutdown of part of the system, resulting in failure of power supply to that part of the system;
86) “Peak Load” means the simultaneous maximum demand of the system occurring under specific time duration (e.g. annual, monthly, daily etc.);
87) “Person” shall include any company or body corporate or association or body of individuals whether incorporated or not, or artificial juridical person;
88) “Phasor Measurement Unit” (PMU) means a device which provides Phasor information (both magnitude and phase angle) for one or more phases of AC voltage or current wave forms in real time;
89) “Pooling Station” means the substation where pooling of generation of individual wind generators or solar generators is done for interfacing with the next higher voltage level;
90) “Powergrid” means the Power Grid Corporation of India limited;
91) “Power Exchange” means the power exchange which has been granted registration in accordance with CERC (Power Market Regulations), 2010 as amended from time to time;
92) “Power System” means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely:

(a) Generating stations;
(b) Transmission or main transmission lines;
(c) Substations;
(d) Tie-lines;
(e) Load despatch activities;
(f) Mains or distribution mains;
(g) Electric supply lines;
(h) Overhead lines/ Under Ground cables;
(i) Service lines;
(j) Works.

93) “Real time data” denotes information relating to current operating state of power system in accordance with system operation and control requirements;

94) “Real time operation” means action to be taken at a given time at which information about the electricity system is made available to the concerned load dispatch centre;

95) “Reactor” means an electrical facility specifically designed to absorb Reactive Power;

96) “Regional Entity” means such persons who are in the RLDC control area and who’s metering and energy accounting is done at the regional level;

97) “Regional Power Committee (RPC)” means a Committee established by resolution by the Central Government for a specific region for facilitating the integrated operation of the power systems in that region;

98) “Regional Energy Account (REA)” means a regional energy account prepared on monthly basis by the RPC Secretariat for the billing and settlement of ‘Capacity Charge’, ‘Energy Charge’ and ‘Transmission Charges’;

99) “Regional Grid” means the entire synchronously connected electric power network of the concerned Region;

100) “Regional Load Despatch Centre (RLDC)” means the Centre established under sub-section (1) of Section 27 of the Act;

101) “Remote Terminal Units (RTU)” means a device suitable for measuring, recording and storing the consumption of Electricity or any other quantity related with electrical system and status of the equipment in real time basis and exchanging such information with the data acquisition system for display and control and shall include, wherever applicable, other equipments such as transducers, relays etc., with necessary wiring and accessories;

102) “Share” means percentage share of a beneficiary in an ISGS or SGS either notified by Government or agreed through contracts and implemented through long/ medium term open access;

103) “Short Term Open Access” means open access for a period upto three months;
104) “Spinning Reserve” means the capacities which are provided by devices including generating station or units thereof synchronized to the grid and which can be activated on the direction of the system operator and effect the change in active power.

105) “Standing Committee for Transmission Planning” means a Committee constituted by the CEA to discuss, review and finalize the proposals for expansion or modification in the ISTS and associated intrastate systems;

106) “State Load Despatch Centre (SLDC)” means the Centre established in the State under subsection (1) of Section 31 of the Act;

107) “State Transmission Utility (STU)” means the Government Company (KSEBL), notified as such by the State Government under sub-section (1) of Section 39 of the Act;

108) “Static VAR Compensator (SVC)” means an electrical facility designed for the purpose of dynamically generating or absorbing Reactive Power;

109) “Supervisory Control and Data Acquisition (SCADA)” means the communication links and data processing systems that acquires the data from Data Provider locations which processes information to enable monitoring, supervision and control as well as decision support;

110) “Surge Impedance Loading (SIL)” means the unity power factor load over a resistive line such that series reactive loss ($I^2X$) along the line is equal to shunt capacitive gain ($V^2Y$), so that the sending end and receiving end voltages and current are equal in magnitude but different in phase position;

111) “Switching over voltages” means over voltages generated during switching of lines, transformers, reactors etc., having wave fronts 250/2500 micro second;

112) “System Stability” means a stable power system i.e. one in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. Usually the perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped;

113) “Technical minimum schedule” in respect of an Intra State Generating Station have the same meaning as provided in Part XI of this Grid Code.

114) “Temporary over voltages” means the power frequency over voltages produced in a power system due to sudden load rejection, single phase to ground faults etc.;

115) “Technical Coordination Committee” means the committee set up by RPC to coordinate the technical and commercial aspects of the operation of the regional grid;
116) “Time Block” means block of 15 minutes each for which Interface Energy Meters record values of specified electrical parameters with first time block starting at 00.00 hrs;

117) “Total Transfer Capability (TTC)” means the amount of electric power that can be transferred reliably over the inter control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency;

118) “Transmission License” means a License granted under Section 14 of the Act, to transmit electricity;

119) “Transmission Planning Criteria” means the policy, standards and guidelines issued by the CEA for the planning and design of the Transmission system;

120) “Transmission Reliability Margin (TRM)” means the amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions;

121) “Trial Run or Trial Operation” in respect of an Intra State Generating Station/ Transmission System have the same meaning as provided under Part XI of this Grid Code.

122) “User” means a person such as a Generating Company including Captive Generating Plant or Transmission Licensee (other than the Central Transmission Utility and State Transmission Utility) or Distribution Licensee or Bulk Consumer, whose electrical plant is connected to the STS at a voltage level equal to or above 66 kV.

(2) The Regulations in this Code shall be interpreted and implemented in accordance with, and not at variance from, the provisions of the Act/ IEGC and the Rules and Regulations made thereunder.

(3) Words, terms and expressions defined in the Electricity Act 2003, IEGC, in the Rules made there under by the Central Government and the State Government and in the Regulations issued by the Central Electricity Authority, the Central Electricity Regulatory Commission and the Commission and used in these Regulations shall have and carry the same meaning as defined and assigned to them in the said Act, Rules and Regulations.

(4) In the interpretation of this Code, unless the context otherwise requires:-

(a) Words in the singular or plural term, as the case may be, shall also be deemed to include the plural or the singular term, respectively;

(b) Reference to any statute, rule, regulation or guideline shall be construed as including all statutory provisions consolidating,
amending or replacing such a statute, rule, regulation or guideline referred to, as the case may be;

(c) Terms “include” and “including” shall be deemed to be followed by “without limitation” or “but not limited to”, regardless of whether such terms are followed by such phrases or words of like import.

(d) The headings are inserted for convenience and may not be taken into account for the purpose of interpretation of these Regulations.

4. Management of the State Grid Code.-

(1) The Kerala State Electricity Board Limited (KSEBL), which is the State Transmission Utility (STU) that also holds the Transmission License, is required to implement and ensure compliance with the Kerala State Electricity Grid Code (KSGC), herein after called the ‘State Grid Code’. To carry out periodic review and seek for amendments of the ‘State Grid Code’, a Review Committee (SGCRC) shall be constituted by the Commission, as detailed in sub Regulation (5)(K) below.

(2) No change in this ‘State Grid Code’ shall be made by the Commission without being deliberated upon and agreed to by the ‘State Grid Code Review Committee’ and approved by the Commission.

(3) The STU will be responsible for managing and implementing the Grid Code for discharging its obligations with the Users. The STU will not be, however, required to incur any expenditure on account of travel etc., of any other member of the panel other than that of its own representatives.

(4) The objective of these Regulations is to define the method of management of State Grid Code documents, submitting and implementing any changes/modifications required in this Code and the responsibilities of the constituents (Users) to effect the change after its approval by the Commission.

(5) Role and Responsibilities of various Organizations and their linkages.-

Consistent with the provisions of the Act, the following sub regulations define the role and responsibilities of various organizations in so far as it relates to the KSGC.

A. Role and Responsibilities of State Load Despatch Centre (SLDC).-

1) Operation and management of STS is an important and complex activity and SLDC shall be the Apex body to ensure integrated operation of the power system in the State. SLDC shall discharge its functions as stated in Sections 32 and 33 of the Act.

2) With reference to KSGC, some of the functions of SLDC shall be as under:

(i) be responsible for optimum scheduling and despatch of electricity
within the State, in accordance with the contracts entered into with the licensees or the generating companies operating in the state. If such Contracts does not exist, the same shall be entered into between the two parties within 6 months of coming into effect of this Code;

(ii) monitor grid operations;
(iii) maintain accounts of the quantity of electricity transmitted through the State grid;
(iv) exercise supervision and control over the State transmission system;
(v) be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the CEA Grid Standards and KSGC/IEGC.

3) The SLDC may levy and collect such fee and charges from the generating companies and licensees using the State transmission system, as may be specified by the Commission:
Provided that in the event of SLDC being operated by the STU, as per the first proviso of sub section (2) of Section 31 of the Act, adequate autonomy as envisaged in Section 32 of the Act, shall be provided to the SLDC to enable it to discharge its functions.

4) The following shall be the exclusive functions of SLDC:-
a) Data acquisition and supervisory control, Grid status estimation, Security analysis.
b) System Operation and control of the State grid covering contingency analysis, contingency ranking and operational planning on real time basis by conducting operational load flow studies using real time data.
c) Furnish feedback to STU on planning, on the issues of transmission strengthening, system protection requirement, system congestion/bottlenecks.
d) Responsible for conducting demand forecast within the State, LGBR analysis, outage planning coordination and operation and analysis of the grid security.
e) Scheduling/ Re-scheduling of Generation.
f) System restoration following grid disturbances.
g) Metering and data collection of the energy transaction within the State Grid.
h) Compiling and furnishing data pertaining to system operation.
i) Operation of State Deviation Settlement Mechanism (DSM) pool account, State Reactive energy account and such other functions as directed by the Commission.
j) Display transmission line loadings, critical lines with contingent conditions and inform STU in writing the transmission bottlenecks for remedial measures under intimation to the Commission.
k) Display of Power Map with power flow in the critical lines.
5) In accordance with Section 33 of the Act, the State Load Despatch Centre in the State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in the State. Every licensee, generating company, generating station, substation and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre under subsection (1) of Section 33 of the Act. The State Load Despatch Centre shall comply with the directions of the Southern Regional Load Despatch Centre.

6) In case of interstate bilateral or collective short term open access transactions having a state utility or an intra state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the Central Electricity Regulatory Commission (Open Access in Inter State Transmission) Regulations, 2008, and KSERC (Connectivity and Intra State Open Access) Regulations, 2013, as amended from time to time.

7) In addition to the above, SLDC shall also,-
   a) Coordinate with the RLDC and RPC on operational matters and represent the DISCOMs in the State in these forums;
   b) Coordinate with critical consumers such as Railways, Airports, Major Industrial consumers etc;
   c) Participate actively in the power system planning of the Region/ Nation;
   d) Coordinate with the STU for planning and execution of the STS.

8) A standby centre called ‘Backup State Load Despatch Centre (BSLDC)’ shall be established to carry out all the functions of SLDC in the absence of the functioning of SLDC and shall,-
   a) be a fully equipped Load Despatch Centre of the state to carry out all the functions of SLDC in an emergency or as and when the SLDC is out of service with full redundancy;
   b) have all controls of LDC functions including administration, finance, accounts etc. when in active mode;
   c) rotate the functioning of SLDC and BSLDC regularly to take care of effective functioning during contingency;
   d) have fully trained, competent, experienced and certified LDC officials for round the clock operation.

B. The Role and Responsibility of the Shift in Charge of SLDC shall be:-
   a) carry out real time power system operation and control within the state to maintain grid discipline during the shift;
b) coordination with SRLDC, CTU, STU, Transmission Licensee, State Generating Stations and Distribution Licensees for smooth and reliable grid operations;
c) ensuring adherence to maintain the injection/ drawal as per schedule for maintaining grid stability;
d) ensuring demand disconnection or generation rescheduling/ backing down as per real time system requirement to operate the grid in compliance with KSGC and ISGC;
e) recording the major activities performed during the shift in the log book;
f) approving declaration of Generator Schedule and requisition of Users and revisions thereof in real time operation;
g) permitting EHV line/ equipment outage and operation thereof;
h) preparation of various reports during the shift;
i) reviewing the demand/ availability in real time, forecasting and proposing for taking machines ON/OFF of the grid as per system requirement and merit order;
j) updating unit outage of generating units and Transmission elements (grid elements only) and ensuring real time data on website.

C. The Roles and Responsibilities of STU,-
1) The STU shall play the role of evacuation of power from the State Generating Stations, supply of power to distribution licensee(s) and exchanging power through inter connection with CTU, IPPs and other entities.
2) STU shall be responsible for coordinating and managing the KSGC. It shall discharge its functions as stated in Section 39 of the Act.
3) With reference to KSGC, some of the functions of STU shall be as under:-
   (i) to undertake coordination of other transmission licensees and users of STS for the effective and reliable transmission of electricity through the state transmission system;
   (ii) to discharge all functions of planning and co-ordination relating to the state transmission system with;
       a) Central Transmission Utility;
       b) State Governments;
       c) Generating companies;
       d) Regional Power Committees;
       e) Authority;
       f) Licensees; and
       g) any other person notified by the State Government in this behalf.
(iii) to ensure development of an efficient, co-ordinated and economical state transmission system for smooth flow of electricity from a generating station to the load centers in coordination with SLDC;

(iv) to provide non discriminatory Open Access as per the provisions in the State Open Access Regulations, to its transmission system for use by -
(a) any licensee or generating company on payment of the transmission charges; or
(b) any consumer as and when such open access is provided under sub-section (2) of Section 42 of the Act, on payment of transmission charges, surcharge, additional surcharge and any other charges thereon, as may be specified by the Commission.

4) In case of open access in intra state transmission, SLDC shall be the Nodal agency for the short term open access and STU shall be the Nodal Agency for medium and long term access. The procedure and modalities in regard to open access shall be as specified in the Kerala State Electricity Regulatory Commission (Connectivity and Intra state Open Access) Regulations, 2013, as amended from time to time.

5) Until a Government Company or any Authority or Corporation is notified by the State Government, the STU shall continue to operate the SLDC, subject to the provisions in sub regulation (A)(3) above.

D. Role of Transmission Licensee(s),-
The main function of the transmission licensee as provided in Section 40 of the Act is to build, maintain and operate an efficient, coordinated and economical Transmission System, comply with the directions of SLDC and provide non discriminatory Open Access.

E. The Role and Responsibility of the Shift in charge of Substation shall be,-
(a) monitoring the real time power system key operational parameters (i.e. Voltage, Current, Power Factor, Active Power, Reactive Power etc.);
(b) during the shift, in case of abnormal operation parameters, take corrective action under intimation to the SLDC and substation in charge;
(c) recording the abnormalities observed and corrective action taken in the log sheet/ computer;
(d) recording abnormalities not attended immediately in the Defect Register as mechanism to inform Substation in charge for early rectification;
(e) issuance of PTW (Permit to Work)/ LCP (Line Clear Permit) ensuring isolation for safety of equipments and maintenance personnel;
(f) furnishing the grid incidents such as tripping of grid elements (lines and transformers) to SLDC immediately on its occurrence and furnish details from DR and Event Logger (EL) as early as possible;
g) following the directions of Shift in charge, SLDC in the case of grid substations or shift in charge of Grid substations in the case of other substations;

h) providing necessary input to the shift in charge of the Grid substation and SLDC as and when needed;

i) all operational instructions from SLDC/ Grid substations shall be complied with immediately even before intimating the official hierarchy and getting instructions.

F. Role of Distribution Licensee,-
The functions of Distribution Licensee shall be as provided in Section 42 of the Act. With reference to KSGC, some of the functions of distribution licensee shall be:-

a) to develop and maintain an efficient, co-ordinated and economical distribution system in its area of supply;

b) to provide non discriminatory open access to its distribution system for use by;
   (i) any licensee or generating company on payment of the distribution charges; or
   (ii) any consumer as and when such open access is provided by the Commission under subsection (2) of Section 42 of the Act, on payment of charges for wheeling and a surcharge thereon, as may be specified by the Commission;

c) In order to facilitate load control, scheduling and despatch, and Open Access operation etc. under the ABT mechanism within the state, each Distribution Licensee shall establish a Distribution Control Center (DCC) within its Area of Supply, having adequate Communication facilities with round the clock manning. It shall take appropriate action in response to any Event in the grid in coordination with the SLDC;

d) The Distribution Licensee shall inform the SLDC about details of the 15 minutes'/ hourly/ daily/ weekly/ monthly demand and energy requirement and also the contracts entered into for importing power from different sources and coordinate with SLDC in its real time operation. It shall follow the directions of SLDC in scheduling its exchange of power and help in controlling the operation of the system by adjustment of drawal from the system. They shall take special care for drawal/ injection of Reactive power from/ to the State Power System.

e) Monitoring and taking corrective actions in respect of the embedded generators and consumers with respect to active and reactive power injection/ withdrawal.

G. Role of Generating Companies,-

a) The generating companies connected to and/or using the STS for evacuating their generation, shall inform the STU and SLDC about the contracts entered into with different parties for exporting power along with its schedule from individual generating station under the company.
b) shall follow the relevant provisions of the KSGC and assist SLDC in the real time operation and control of the system and scheduling of generation;
c) shall operate the generating stations as per the directions of SLDC;
d) shall provide active and reactive power support as per grid requirements when asked for by SLDC, irrespective of the contracts in case of contingencies;
e) shall arrange fuel/ monitor availability of water in the reservoir so as to keep the generation ready when asked by the buyer/ SLDC;
f) shall declare availability of the station with respect to the active power capability and the energy injection possible on daily basis.

H. Role of Embedded Open Access consumers,-
The Embedded open access consumers shall,

a) restrict their drawal as per the drawal schedule furnished to the distribution licensee and SLDC in real time operation;
b) segregate non-essential load in their premises and shall equip to receive Automatic Demand Management Signal received from SLDC for maintaining grid discipline.

I. Role of Prosumers,-
The Prosumers shall,

a) ensure that the active and reactive power flows at the interconnection point are within limits;
b) not inject reactive power into the grid when the voltage is high and vice versa. Reactive power support shall be provided when specifically asked by SLDC irrespective of the voltage at the point of interconnection.

J. Role of NLDC, SRLDC, SRPC, CTU and CEA,-
The functioning of these entities shall be in accordance with the provisions of the Act and as defined in Regulations 2.2 to 2.6 of IEGC, 2010, as amended from time to time.

K. State Grid Code Review Committee (SGCRC),-
1) A State Grid Code Review Committee (SGCRC) shall be constituted by the Commission within 60 days from the date of coming into force of this State Grid Code. The Commission Secretary shall inform STU and all Users of the names and addresses of the Committee Chairman and Member Secretary within 15 days of the approval of the Committee. The Commission shall inform Users in writing of any subsequent changes. The existing SGCRC shall continue until the new Committee is formed.
2) The State Grid Code Review Committee shall be chaired by the Member (Technical) of the Commission and consist of the following members, namely,
a) Member (Technical), KSERC – Chairman  
b) Director (Technical), KSERC – Member Secretary  
c) Director (Transmission) of KSEBL - Member  
d) Director (Generation) of KSEBL - Member  
e) Director (Distribution) of KSEBL – Member  
f) Chief Engineer (SLDC) - Member  
g) One representative from among the other distribution licensees in the State (nominated by the Commission) - Member  
h) One representative of the IPPs/ CPPs in the State (to be nominated by the Commission) – Member  
i) One representative each from NTPC, PGCIL, SRPC and SRLDC may participate in the Committee as special invitees.

The SGCRC Secretary shall request NTPC, PGCIL, SRPC and SRLDC to inform the name and designation with contact details of their representatives to the Committee within 15 days of the constitution of the SGCRC. They shall inform the Committee Secretary, in writing, of the details of their representative to the Committee within 30 days and shall also inform any subsequent changes.

3) A member, in case of exigency, may nominate another person to represent him for the Meeting, subject to his participation being approved by the Chairman of the Committee.

4) Any other member can be co-opted as a member of the panel as directed by the Commission.

5) The Chairman can include specialized technical experts in the panel meetings for specific expert opinion.

6) **State Grid Code Review Committee Proceedings,-**
   a) The Rules to be followed by SGCRC in conducting their business shall be formulated by the Committee itself and approved by the Commission. The SGCRC shall meet at least once in six months.
   b) The functions of the State Grid Code Review Committee shall be as follows,-
      i) to scrutinize and review the State Grid Code and its implementation;
      ii) to propose any revision, if necessary, in the State Grid Code consequent to analysis report on major grid disturbance soon after its occurrence. The recommendations of the Committee shall be submitted to the Commission for approval and the Commission may issue such directives to the Users for taking necessary remedial measures, as may be deemed fit, to prevent its recurrence;
      iii) to consider all requests for amendment to the State Grid Code as may be made by the Users;
      iv) to issue guidance on the interpretation and implementation of the State Grid Code;
v) to examine problems raised by the Users;
vi) to review the monitoring and coordination functions for the operation and protection of the state grid.

c) Meetings may be held by STU with a user to discuss individual requirements and with groups of users to prepare proposals for the Committee meeting. The Committee may set up sub committees for detailed study of related problems.
d) The Commission on the application of the users or otherwise, call emergency meeting of SGCRC as and when the situation so demands and make such alterations and amendments in the State Grid Code, as it deems fit.

5. **State Grid Code Review and Revisions.**

   (1) SGCRC shall, in consultation with such other persons as the Commission may direct, review the State Grid Code and its implementation in every five years or earlier, if required by the Commission.

   (2) The Commission reserves the right to review the State Grid Code as and when required.

   (3) The Member Secretary of SGCRC shall present all proposals for revision of the State Grid Code to the Committee for its consideration.

   (4) The Secretary shall send to the Commission the following reports at the conclusion of each review meeting of the Committee;

(i) A report on the outcome of such review;

(ii) Any proposed revisions to the State Grid Code, as SGCRC considers reasonable and necessary for the achievement of the objectives of the State Grid Code, along with justification therefore.

   (5) All revisions to the State Grid Code shall require prior written approval of the Commission.

   (6) Subject to the conditions in the sub regulations below, all proposals for revisions in the State Grid Code shall be decided by consensus in the meeting of State Grid Code Review Committee. However, where consensus cannot be arrived at in two sessions of the State Grid Code Review Committee, it will be with the majority of members voting. In the event of no decision being arrived at by majority in two sessions, the matter shall be referred to the Commission for a decision. All revisions in the State Grid Code shall be effected as per the provisions of the Act/IEGC and after approval by the Commission.

   (7) In any unusual situation where normal the day to day operation is not possible without revision of some provision(s) of the State Grid Code, a provisional revision may be implemented before its approval by the Commission. This shall however be done only after discussions at a special meeting of State Grid Code Review Committee convened on emergency basis. The Commission shall be intimated and approval shall be sought at the earliest but not later than 15 days after the provisional revision by recorded means of communication.
(8) The amendments proposed by the State Grid Code Review Committee shall be consistent and compatible with IEGC.

(9) The Commission may issue directives to SGCRC to revise, supplement or replace the State Grid Code in such manner as may be specified in those directives and SGCRC shall forthwith comply with such directives.

(10) SGCRC shall convey to all concerned, revisions to the State Grid Code after approval by the Commission and the same shall be incorporated in the subsequent version of the State Grid Code.

(11) The revision number and date of issue shall appear on every page of the State Grid Code. Every change from the previous version shall be clearly marked in the margin. In addition, the revisions shall be entered in the Code Revision Sheet given below, with the number of every changed Regulation, together with a brief statement of change.

**State Grid Code Revision Sheet**

<table>
<thead>
<tr>
<th>Revision No</th>
<th>Date</th>
<th>Regulations revised</th>
<th>Brief statement of changes made</th>
</tr>
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(12) The SGCRC shall make available copy of the State Grid Code in force, for sale to any person requesting for it.

(13) The SGCRC shall keep an up-to-date list of the recipients and locations of all authenticated copies of the State Grid Code.

(14) STU and SLDC shall put the latest State Grid Code with the list of amendments on their web sites.

6. **Functional Committees.**-

(1) The STU is responsible for coordinating and managing the State Grid Code, whereas the State Grid Code Review Committee shall be responsible to keep the implementation of the State Grid Code under scrutiny and review for any changes, modifications therein. The State Grid Code Review Committee shall constitute the following functional committees for the implementation of the State Grid Code:

a) Planning Code: Transmission Planning Committee (TPC)

b) System Operation Code: State Operation and Co-ordination Committee (SOCC)

c) Protection and Communication Code: State Protection Co-ordination Committee (SPCC)

d) Energy Accounting and Metering Code: Commercial and Metering Committee (CMC)

(2) The State Grid Code Review Committee shall nominate the members of the functional committees, ensuring adequate representation to distribution licensee(s) and Generation Companies also. Chairman and Member Secretary of the functional committees shall be from STU/ SLDC, as applicable.
(3) The State Grid Code Review Committee can formulate any other Operational Committee, as it deems fit, for the implementation of the State Grid Code.

7. Transmission Planning Committee (TPC).-

(1) Transmission Planning Committee shall coordinate the implementation of Planning Code (Chapter II) to ensure system planning coordination for the state as a whole.

(2) TPC shall comprise of members to be nominated by the State Grid Code Review Committee, consisting representatives of STU, Transmission licensees, Distribution licensees, Generation companies of installed capacity of 100 MW and above, Wind generators of capacity 10 MW and above at pooling station level, Solar generators of capacity 50 MW and above at pooling station level and SLDC. TPC shall meet at least once in every six months and deliberate on all technical and operational aspects of Planning Code and shall give their recommendations to the State Grid Code Review Committee.

(3) The rules to be followed by the Committee in conducting their business shall be formulated by the Committee with the approval of the State Grid Code Review Committee.

(4) The committee shall perform the following functions:
   (i) Co-ordination of system planning, execution of works, maintenance schedule and contingency plan to ensure availability of adequate transmission and distribution system;
   (ii) Review the existing interconnection equipments for alteration, if necessary, so as to comply with the Connection conditions provided for in the State Grid Code;
   (iii) Review the load forecast and the methodology and assumptions made by Users;
   (iv) Review and finalize the proposals identified on the basis of planning studies.

8. State Operation and Co-ordination Committee (SOCC).-

(1) State Operation and Co-ordination Committee shall coordinate the implementation of Operating Code (Chapter III) and Scheduling and Despatch Code (Chapter IV) to ensure that respective Generators and Distribution Licensees using State Transmission System discharge their obligations under the State Grid Code.

(2) SOCC members shall be nominated by the State Grid Code Review Committee, consisting representatives of STU, Transmission licensees, Distribution licensees, Generation companies of installed capacity 100 MW and above, Wind generators of capacity 10 MW and above at pooling station level, Solar generators of capacity 50 MW and above at pooling station level and SLDC. SOCC shall meet once every three months and deliberate on all technical and operational aspects of Load Despatch and
System Operation and shall give their recommendations to the State Grid Code Review Committee.

(3) The rules to be followed by the Committee in conducting its business shall be formulated by the Committee itself and shall be approved by the State Grid Code Review Committee.

(4) The Committee shall perform the following functions:
(i) Review the reactive power compensation in the State Transmission System;
(ii) Review the load shedding mechanisms;
(iii) Review and analyze the grid disturbances and system restoration procedure;
(iv) Review and finalize amendments of Outage Plan of State Transmission System and generating stations;
(v) Deliberate and prepare the Under Frequency Load Shedding Schemes and the mechanism to be adopted for the same for various substations to ensure that the frequent tripping of same feeder is avoided;
(vi) Review the availability of Disturbance Recorders, Event Loggers in the State Transmission System and generating stations;
(vii) Review the performance of Free Governing/ Restricted Governing system for all the generating stations;
(viii) Review the status of Reactive power support to the System from the generating stations including solar and wind generators.

9. **State Protection Co-ordination Committee (SPCC).**

(1) State Protection Co-ordination Committee shall coordinate the implementation of Protection Code (Chapter V) and Communication Code (Chapter VII), to ensure that respective Users using State Transmission System discharge their obligations under the Protection and Communication Code.

(2) State Protection Co-ordination Committee members shall be nominated by the State Grid Code Review Committee, and shall include representatives of STU, Transmission licensees, Distribution licensees, Generation companies of installed capacity 100 MW and above, Wind generators of capacity 10 MW and above at pooling station level, Solar generators of capacity 50 MW and above at pooling station level and SLDC. SPCC shall meet once in every three months and shall give their recommendations to the State Grid Code Review Committee.

(3) The rules to be followed by the State Protection Co-ordination Committee in conducting its business shall be formulated by the Committee with the approval of the State Grid Code Review Committee.

(4) The Committee shall perform the following functions:-

(i) Keep Protection and Communication Codes and its implementation under scrutiny and review and ensure compliance thereof;
(ii) Consider all requests for amendment to the Protection Code which any User makes;

(iii) Create awareness about various issues related to the Protection and Communication Codes;

(iv) Deliberate and decide various protection settings, testing procedure and periodicity;

(v) Review and specify the minimum protection and communication requirements for the User’s system connected to the State Transmission System;

(vi) Deliberate and decide regarding gradation of protection schemes and necessary switchgear equipments;

(vii) Review and analyze the operation of protection system in case of grid disturbance and recommend modifications and improvements;

(viii) The relay settings and relay coordination calculations shall be kept by the concerned entity and also at STU and SLDC at state level. Any revision of settings shall be done only with the prior approval of the Committee;

(ix) Take into cognizance of the recommendations and directions of Regional Protection Coordination subcommittee of SRPC and communication subcommittee of SRPC and implement the directions within the prescribed time limit.

10. **Commercial and Metering Committee (CMC),**

(1) Commercial and Metering Committee shall coordinate the implementation of the Metering Code (Chapter VI) to ensure that the respective constituents discharge their obligations under the Metering Code.

(2) The Committee shall also be responsible for coordinating the preparation of state energy account in accordance with the provisions of the State Grid Code.

(3) The Committee members shall be nominated by the State Grid Code Review Committee, and include representatives of STU, Transmission licensees, Distribution licensees, Generation companies of installed capacity 100 MW and above, Wind generators of capacity 10 MW and above at pooling station level, Solar generators of capacity 50 MW and above at pooling station level and SLDC. CMC shall meet once in every two months.

(4) The rules to be followed by the Commercial and Metering Committee in conducting its business shall be formulated by the Committee with the approval of the State Grid Code Review Committee.

(5) The Committee shall perform the following functions:

(i) Keep Metering Code and its implementation under scrutiny and review and ensure compliance thereof;

(ii) Consider all requests for amendment to the Metering Code which any User makes;
(iii) Create awareness about various issues related to the Metering Code;
(iv) Review deviations in the existing CTs and VTs/ CVTs from the minimum specifications prescribed in the State Grid Code and upgradation/ replacement of the same within one year of coming into effect of the State Grid Code;
(v) Deliberate and decide the issues relating to the monthly energy account and settlement prepared by SLDC;
(vi) Resolve any energy accounting and settlement disputes arising out of metering failure;
(vii) Review and propose amendments, if necessary, in the methodology and principles for maintaining State Energy Accounts;
(viii) Resolve billing disputes and complaints regarding Open Access consumers as per the redressal mechanism under KSERC (Connectivity and Intra state Open Access) Regulations 2013, as amended from time to time.

11. Non-compliance and Derogation,-
(1) If any User fails to comply with any provision of the State Grid Code, the SLDC/ STU shall report non compliance of the State Grid Code to State Grid Code Review Committee without delay, under intimation to the concerned user. Any other User can also report non compliance of State Grid Code by any other user/ SLDC/ STU to SGCRC. SLDC/ STU/ SGCRC shall promptly take remedial action for compliance.
(2) Wrong declaration of capacity, non-compliance of SLDC’s load despatch instructions, non-compliance of SLDC’s instructions for backing down without adequate reasons, non-furnishing of data etc. constitute non-compliance of State Grid Code and thus the contravention of Regulations of the Commission. It may attract provisions of Section 33(5) or Section 142 of the Act.
(3) Consistent failure to comply with the State Grid Code may lead to disconnection of the User’s plant and/or facilities.
(4) Derogation, if any, for any particular Regulation or clauses or provision of the State Grid Code shall be with the express permission of the Commission for a specified time. Derogation of any requirement of the State Grid Code shall be an exception and not the norm, and will be allowed only when it is impossible and not just difficult or inconvenient for the User to comply with in the required time scale. Failure to comply with fixed time derogation by any User shall carry a financial penalty not exceeding rupees five lakhs or as may be decided by the Commission.
Chapter II – PLANNING CODE
Part II - SYSTEM PLANNING

12. **Introduction:-**

(1) In accordance with Section 3(4) of the Act, CEA shall inter-alia prepare a National Electricity Plan in accordance with the National Electricity Policy and notify such plan once in five (5) years. Further as per Section 3(5) of the Act, CEA may review or revise the National Electricity Plan in accordance with the National Electricity Policy.

(2) Section 73(a) of the Act requires the CEA to advise the Central Government on the matters relating to the National Electricity Policy, formulate short term and perspective plans for development of the electricity system and co-ordinate the activities of planning agencies for optimal utilization of resources to subserve the interests of the national economy and to provide reliable and affordable electricity for all consumers.

(3) This part specifies the methods for data submission by the users to STU for planning and development of the State Transmission System. It also specifies the procedure to be applied by STU in the planning and development of an efficient, co-ordinated, secure and economical State Transmission System and the connectivity to the Regional/ National Grid.

(4) Requirement for reinforcement or extension of the State Transmission System may arise for a number of reasons, including but not limited to the following,-

(i) Development on a User's system already connected to the State Transmission System;

(ii) The introduction of a new Connection Point between the User's system and the State Transmission System;

(iii) For Evacuation of power from Generating Stations within or outside the State;

(iv) For developing adequate Reactive Power Compensation to the system;

(v) A general increase in system capacity, due to addition of generation Capacity or increase in system load;

(vi) Transient and steady state stability considerations;

(vii) Cumulative effect of any of the above.

(5) The reinforcement or extension of the State Transmission System may involve work at an entry or exit point (Connection point) of a User to the State Transmission System. Since development of all User's systems must be planned well in advance to ensure consent and right of way to be obtained, detailed engineering design and construction work to be completed, STU will require information from Users and vice versa. To this effect, the Planning Code imposes time frames, for exchange of necessary information between STU and Users, giving due regard where necessary, to the confidentiality of such information.
(6) The Planning Code:-

a) Defines the procedure for the exchange of information between the STU and a User in respect of any proposed development on the User’s system, which may have an impact on the performance of the User;

b) Details the information which STU shall make available to Users in order to facilitate the identification and evaluation of opportunities for use of or connection to the State Transmission System;

c) Details the information required by STU from Users to enable STU to plan the development of its Transmission System to facilitate proposed User developments;

d) Specifies planning and design standards, which shall be applied by STU in planning and development of the power system.

13. Planning Policy,-

(1) STU would develop, in consultation with SLDC and the Users, a Perspective rolling Transmission plan for the next 10 years for the State Transmission System. These Perspective Transmission plans shall be updated every year to take care of the revisions in load projections and generation capacity additions. The updated perspective plans shall be submitted to the Commission for approval by 30th November of each year, along with the Capital Investment Plan.

(2) STU shall carry out annual planning process corresponding to a five year forward term for identification of major State Transmission System schemes which shall be dovetailed into the National Electricity Plan prepared by CEA on 5 years short term basis.

(3) STU shall carry out network studies and review fault levels for planning system strengthening and augmentation.

(4) The STU shall coordinate with Distribution licensees, Urban Planning Agencies, Special Economic Zones, Industrial Area Developers etc., to keep adequate provision for transmission corridor and land for new substations for their long term requirements.

(5) The primary responsibility for load forecasting within the area of supply shall be of the Distribution Licensee. Distribution Licensees shall determine the peak load and energy forecasts of their areas for each of the succeeding years and submit the same annually by 30th April, to STU. These shall include the details of demand forecasts, data methodology and assumptions on which the forecasts are based. The peak load and energy forecasts shall be made for the overall area of supply. The annual peak load forecast shall also be made for each Connection Point/ Interface Point with the Transmission System. These forecasts shall be
updated annually and also whenever major changes are made in the existing system. Wherever these forecasts take into consideration demands for power exceeding 1MW by a single consumer, the Distribution Licensee shall personally satisfy himself regarding the materialization of such a demand.

(6) CEA would formulate Perspective Transmission Plan for Inter State Transmission System (ISTS) and STU shall formulate the perspective plan for Intra State transmission system. These perspective transmission plans would be continuously updated to take care of the revisions in load projections and generation scenarios, considering the seasonal and the time of the day variations. In formulating this perspective Transmission Plan, the transmission requirement for evacuating power from renewable energy sources should also be considered. The transmission system required for Open Access should also be taken into account in accordance with National Electricity Policy so that congestion in system operation is minimized.

(7) The STU shall carry out the planning process from time to time as per the requirement, for identification of Intra State Transmission System including the transmission system associated with Generation Projects, strengthening of Intra State Transmission System to absorb/evacuate power from the ISTS in coordination with the CTU to optimize the utilization of the Integrated Transmission network. While planning schemes, the following shall be considered in addition to the authenticated data collected from and in consultation with the users by the STU:
   a) Perspective Plan formulated by CEA;
   b) Electric Power Survey of India published by CEA;
   c) Transmission Planning Criteria and guidelines issued by CEA;
   d) Operational feedback from SRPC/ SRLDC/ SLDC;
   e) Central Electricity Regulatory Commission (Grant of Connectivity, Long term Access and Medium term Open Access in inter State Transmission and related matters) Regulations, 2009 and KSERC (Connectivity and Intra State Open Access) Regulations, 2013 as amended from time to time;
   f) Renewable energy capacity addition plan issued by the Ministry of New and Renewable Energy (MNRE), Govt. of India and the State Agencies (EMC/ ANERT);
   g) Feedback from CTU on the LTA granted to ISGS, IPPs and Bulk consumers.

(8) STU shall follow the following steps in planning,-
   a) Forecast the demand for power within the Area of Supply, based on
the forecasts provided by Distribution Licensees, and provide to the Commission details of the demand forecasts, data, methodology and assumptions on which the forecasts are based. These forecasts shall be annually reviewed and updated;
b) Prepare a proposal in consultation with SLDC, requirement of generation for the State to meet the load demand as per the forecast, after examining the economic, technical and environmental aspects of all available alternatives taking into account the existing contracted generation resources and effects of demand side management;
c) Prepare a transmission plan for the State Transmission System compatible with the above load forecast and generation plan. This will include provision for VAR compensation needed in the State Transmission System;
d) The reactive power planning exercise is to be carried out by STU in consultation with SLDC and Distribution Licensees, as per the Commission’s directives, if any, and programmed for installation of reactive compensation equipments by the STU and Distribution Licensees;
e) STU’s planning department shall use load flow, short circuit, transient stability studies and other techniques for transmission system planning;
f) STU’s planning department shall simulate the contingency and system constraint conditions for the system for transmission system planning;
g) STU shall maintain a historical database based on operational data supplied by SLDC using the state of the art tools such as Energy Management System (EMS) for demand forecasting;
h) STU shall prepare and submit the first long term plan within 6 months of commencement of this Code to the Commission taking into consideration the projected generation expansion and transmission system expansion to fully meet the energy requirement and peak demand for the plan period and to create adequate reserve capacity margin;
i) The STU shall coordinate with the CTU for eliminating transmission constraints in a cost effective manner.

(9) All the Users shall supply to the STU, the planning data prescribed in Appendix A and Appendix B, by 30th April of every year to enable STU to formulate and finalize the updated plan by 30th November of each year for the next 5 years.

14. Planning Criteria,-

(1) The State Transmission System planning and generation expansion
planning shall be done in accordance with the provisions of the planning criterion as specified in Clause 3.5 of IEGC. However, some planning parameters of the State Transmission System may vary according to the directives of the Commission.

(2) The planning criterion shall be based on the security philosophy on which both ISTS and the State Transmission System have been planned. The security philosophy shall be as per the Transmission Planning Criteria and other guidelines, as given by CEA.

(3) The STU shall also consider the following for the purpose of preparing the transmission system plan under these Regulations:

(i) Plans formulated by the Authority for the transmission system under the provisions of clause (a) of Section 73 of the Act;

(ii) Latest available Electric Power Survey of the Authority;

(iii) Short term and Long term Power Procurement Plan approved by the Commission;

(iv) Grid Standards specified by the Authority under clause (d) of Section 73 of the Act;

(v) Transmission Plan formulated by Central Transmission Utility under the provisions of the Grid Code specified by Central Electricity Regulatory Commission under clause (h) of Section 79 (1) of the Act;

(vi) Transmission Planning Criteria and Guidelines issued by the Authority;

(vii) Recommendations/ inputs, if any, of the Southern Regional Power Committee (SRPC);

(viii) National Electricity Plan/ National Electricity Policy which are relevant for development of STS;

(ix) N-1 security for evacuating power from generating stations of capacity 50MW and above and substations having transformation capacity above 100MW. In the case of substations, the transformation capacity in the upstream stations shall also have N-1 security;

(x) Any other information/ data source suggested by the Commission.

15. Planning Responsibility,

(1) The primary responsibility of load forecasting within Distribution Licensee’s Area of Supply rests with respective Distribution licensees. The Distribution licensees shall determine month wise peak load and energy forecasts of their areas for each category of loads for each of the succeeding 10 years as per the established procedure and submit the same annually by 30th April to STU along with details of the demand
forecasts, data, methodology and assumptions on which the forecasts are based, along with their proposals for transmission system augmentation. The load forecasts shall be made for each of the existing as well as proposed interconnection points between STU and Distribution Licensees and shall include annual peak load and energy projections. The peak load requirement at each Connection Point/ Interface Point will essentially ensure that, the STU may determine the corrective measures to be taken to maintain the capacity adequacy in the Transmission System upto the Connection Point/ Interface Point. This will facilitate the Transmission Licensee to develop the compatible Transmission System.

If the Distribution Licensee receives power at a number of Connection Points/ Interface Points in a compact area, which are interconnected in a ring, then such a Distribution Licensee shall forward the overall long term demand forecast for the overall area of supply as well as at each Connection Point/ Interface Point with the variation or tolerance, as mutually discussed and agreed upon with the STU. The demand forecasts shall be updated annually or whenever major changes are made in the existing forecasts or planning. While indicating requirements of single consumers with large demands (1MW or higher), the Distribution licensee shall satisfy itself as to the degree of certainty of the demand materializing.

(2) SGS shall provide their generation capacity to STU for evacuating Power from their power stations for each of the succeeding 10 years along with their proposals for transmission system augmentation and submit the same annually by 30th April to STU.

(3) The planning for strengthening the State Transmission System for Evacuation of power from outside the State stations shall be initiated by STU.

(4) Transmission Planning Committee consisting of members from each Distribution Licensee, STU and SGS shall review and approve the load forecasts and the methodology followed by each of the Distribution Licensees.

(5) The State Transmission System proposals identified based on Planning studies would be discussed, reviewed and finalized by the Transmission Planning Committee.


(1) The applicants seeking long term transmission service are required to provide their end-to-end requirements well in advance, considering the time required for implementation of the transmission project, to the STU so as to make available the requisite transmission capacity and minimize situations of congestion and stranded assets. They shall also provide a
basis for their transmission requirement such as size and completion schedule of their generation facility, demand based on EPS and their commitment to bear transmission service charges.

(2) Planning of transmission system for evacuation of power from hydro projects shall be done river basin wise considering the identified generation projects and their power potential.

(3) In case of highly constrained areas like congested urban/ semi-urban areas, very difficult terrain etc., the transmission corridor may be planned by taking long term perspective of optimizing the right-of-way and cost. This may be done by adopting higher voltage levels for final system and operating one level below in the initial stage, or by using multi-circuit towers for stringing circuits in the future, or using new technology such as HVDC, GIS, GIL, Monopoles, EHV UG cables, HTLS conductors etc.

(4) In accordance with Section 39 of the Act, the STU shall act as the nodal agency for STS planning in coordination with distribution licensees and intra-State generators connected/ to be connected in the State grid. The STU shall be the single point contact for the purpose of STS planning and shall be responsible on behalf of all the intra State entities, for evacuation of power from State generating stations, meeting requirements of distribution licensees and drawing power from ISTS commensurate with the ISTS Plan.

(5) Normally, the various intra State entities shall be supplied power through the intra State network. Under exceptional circumstances, the load serving intra State entity may be allowed direct interconnection with ISTS on recommendation of STU, provided that such an entity would continue as intra-State entity for the purpose of all jurisdictional matters including energy accounting. Under such situation, this direct interconnection may also be used by other intra State entities.

(6) The system parameters and loading of system elements shall remain within the prescribed limits. The adequacy of the transmission system should be tested for different feasible load-generation scenarios as detailed subsequently in this document.

(7) The system shall be planned to operate within permissible limits both under normal as well as after more probable credible contingency as detailed in this Grid Code. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/ rare but credible contingencies should be identified from time to time and suitable defense mechanism, such as; load shedding, generation rescheduling, islanding, system protection schemes etc., may be worked out to mitigate their adverse impact.
The following options may be considered for planning of the transmission network. The choice shall be based on cost, reliability, right-of-way requirements, transmission losses, down time (in case of up-gradation and re-conductoring options) etc.,

a) Addition of new transmission lines/ substations to avoid overloading of existing system including adoption of next higher voltage.
b) Application of FACTS devices namely, Series Capacitors, Phase Shifting Transformers etc. in existing and new transmission systems to increase power transfer capability.
c) Up gradation of the existing AC transmission lines to higher voltage using same right of way.
d) Re-conductoring of the existing AC transmission line with higher Ampacity conductors.
e) Use of multi voltage level and multi circuit transmission lines.
f) Use of narrow base towers and pole type towers in semi-urban / urban areas keeping in view cost and right-of-way optimization.
g) Use of HVDC transmission – both conventional and Voltage Source Convertor (VSC) based.
h) Use of GIS/ Hybrid switchgear (for urban, coastal, polluted areas etc.).
i) Use of EHV cables and any other appropriate upcoming technologies.

Critical loads such as - Railways, Metro rail, Airports, Refineries, Underground mines, Steel plants, Smelter plants, Critical care Hospitals etc., shall plan their interconnection with the grid, with 100% redundancy and as far as possible from two different sources of supply, in coordination with the STU.

Appropriate Communication system for the new substations and generating stations may be planned by the STU and implemented by licensees as well as generation developers so that the same is ready at the time of commissioning.

Minimum safety working clearance shall be maintained horizontally, vertically and in between the live conductors of the system, to conform to the specifications and standards as provided in the CEA (Measures relating to safety and electric supply) Regulations, 2010, as amended from time to time.

17. **Criteria for Steady State and Transient State behavior,**
The transmission system shall be planned considering the following general principles:-

a) In normal operation (‘N-0’) of the grid, with all the elements to be available in service, it is required that all the system parameters like
voltages, loadings, frequency should remain within permissible normal limits.
b) The grid may however be subjected to disturbances and it is required that loss of any one element (‘N-1’ or single contingency condition), all the system parameters like voltages, loadings, frequency shall be within permissible normal limits.
c) After suffering one contingency, grid is still vulnerable to experience second contingency, though less probable (‘N-1-1’), wherein some of the equipments may be loaded upto their emergency limits. To bring the system parameters back within their normal limits, load shedding/re-scheduling of generation may have to be applied either manually or through automatic system protection schemes (SPS). Such measures shall generally be applied within one and a half hours (1½) after the disturbance.

18. **Permissible Normal and Emergency limits,-**
Normal thermal ratings and normal voltage limits represent equipment limits that can be sustained on continuous basis. Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time which may be one hour to two hour depending on design of the equipment. The normal and emergency ratings to be used in this context are given below:-

19. **Loading limits,-**
a) The loading limit for a transmission line shall be its thermal loading limit, determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient etc.
In Kerala, the ambient temperature may be taken as 45° Celsius. The maximum permissible thermal line loading for different types of Transmission line configurations, employing various types of conductors shall be as provided under Table II, in Annexure V of CEA Manual on Transmission Planning Criteria, 2013.
b) Design of transmission lines with various types of conductors should be based on conductor temperature limit, right-of-way optimization, losses in the line, cost, reliability considerations etc.
c) The loading limit for an Inter connecting transformer (ICT) shall be its name plate rating. Provided that, during planning a margin as specified in these Regulations shall be kept in the above Transmission lines/transformer loading limits.
d) The emergency thermal limits for the purpose of planning shall be 110% of the normal thermal limits.
20. Voltage limits,-
   a) The steady state voltage limits are given in the Table below:

<table>
<thead>
<tr>
<th>Voltage in (kV rms)</th>
<th>Normal rating</th>
<th>Emergency rating</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Nominal</td>
<td>Maximum</td>
</tr>
<tr>
<td>765</td>
<td>800</td>
<td>728</td>
</tr>
<tr>
<td>400</td>
<td>420</td>
<td>380</td>
</tr>
<tr>
<td>220</td>
<td>245</td>
<td>198</td>
</tr>
<tr>
<td>110</td>
<td>123</td>
<td>99</td>
</tr>
<tr>
<td>66</td>
<td>72.5</td>
<td>60</td>
</tr>
</tbody>
</table>

   b) Temporary Over Voltage limits due to sudden load rejection:
      (i) 800kV class system 1.4 p.u. peak phase to neutral (653 kV = 1 p.u.)
      (ii) 420kV class system 1.5 p.u. peak phase to neutral (343 kV = 1 p.u.)
      (iii) 245kV class system 1.8 p.u. peak phase to neutral (200 kV = 1 p.u.)
      (iv) 123kV class system 1.8 p.u. peak phase to neutral (100 kV = 1 p.u.)
      (v) 72.5kV class system 1.9 p.u. peak phase to neutral (59 kV = 1 p.u.)

c) Switching Over Voltage limits:
      (i) 800kV class system 1.9 p.u. peak phase to neutral (653 kV = 1 p.u.)
      (ii) 420kV class system 2.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

21. Criteria for system with No Contingency (‘N-0’),-
   a) The system shall be tested for all the load-generation scenarios.
   b) For the planning purpose all the equipments shall remain within their normal thermal loading and voltage rating.
   c) The angular separation between adjacent nodes or substations (buses) shall not exceed 30 degree.
Reliability Criteria (22 to 24)

22. Criteria for Single Contingency (‘N-1’),-

A. Steady State,-

i) All the equipments in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following elements (called single contingency or ‘N-1’ condition), but without load shedding/ rescheduling of generation,-

   a) Outage of a 110 kV or 66 kV single circuit,
   b) Outage of a 220kV single circuit,
   c) Outage of a 400kV single circuit,
   d) Outage of a 400kV single circuit with Fixed Series Capacitor (FSC)
   e) Outage of an Inter Connecting Transformer (ICT),
   f) Outage of a 765kV single circuit,
   g) Outage of one pole of HVDC bi pole.

ii) The angular separation between adjacent buses under (‘N-1’) conditions shall not exceed 30 degree.

B. Transient State,-

Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. The transmission system shall be stable after it is subjected to one of the following disturbances,-

(i) The system shall be able to survive a permanent three phase to ground fault on a 765kV line close to the bus to be cleared in 100 milli seconds (ms).

(ii) The system shall be able to survive a permanent single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

(iii) The system shall be able to survive a permanent three phase to ground fault on a 400kV line close to the bus to be cleared in 100 ms.

(iv) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

(v) In case of 220kV/ 110kV/ 66kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a
bus, with a fault clearing time of 100 ms (5 cycles) assuming 3-pole opening.

(vi) The system shall be able to survive a fault in HVDC Convertor Station, resulting in permanent outage of one of the poles of HVDC Bi pole.

(vii) Contingency of loss of generation,-
The system shall remain stable under the contingency of outage of single largest generating unit or a critical generating unit.

23. **Criteria for Second Contingency (‘N-1-1’),**-
Under the scenario where a contingency as defined at Regulation 22 has already happened, the system may be subjected to one of the following subsequent contingencies (called ‘N-1-1’ condition),-

(a) The system shall be able to survive a temporary single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and successful re-closure (dead time 1 second) shall be considered.

(b) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

(c) In case of 220kV/ 110kV/ 66kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 100ms (5 cycles) assuming 3-pole opening.

(d) In the ‘N-1-1’ contingency condition as stated above, if there is a temporary fault, the system shall not lose the second element after clearing of fault but shall successfully survive the disturbance.

(e) In case of permanent fault, the system shall loose the second element as a result of fault clearing and thereafter, shall asymptotically reach to a new steady state without losing synchronism. In this new state the system parameters (i.e. voltage and line loading) shall not exceed emergency limits, however, there may be requirement of load shedding/ rescheduling of generation so as to bring system parameters within normal limits.

24. **Criteria for radially connected Generator Feeder with the grid,**-
For the transmission system connecting generators or a group of generators radially with the grid, the following criteria shall apply:-
a) The radial system shall meet ‘N-1’ reliability criteria as given at Regulation 22, for both the steady state as well as transient state.
b) For subsequent contingency i.e., ‘N-1-1’ (Regulation 23) only temporary fault shall be considered for the radial system.
c) If the ‘N-1-1’ contingency is of permanent nature or any disturbance/contingency causes disconnection of such generator/group of generators from the main grid, the remaining main grid shall asymptotically reach to a new steady state without losing synchronism after loss of generation. In this new state the system parameters shall not exceed emergency limits, however, there may be requirement of load shedding/rescheduling of generation so as to bring system parameters within normal limits.

Criteria for Simulation and Studies (25 to 32)

25. System Studies for Transmission Planning,-

1) The system shall be planned based on one or more of the following power system studies as per requirements,-

   i) Power Flow studies;
   ii) Short Circuit Studies;
   iii) Stability Studies (including transient stability and voltage stability);
   iv) EMTP studies (for switching/dynamic over voltages, insulation coordination etc.) for Power System Protection.

2) The candidate lines for system studies may be selected from lines having angular difference between its terminal buses >20 degree after contingency of one circuit.

26. Power System Model for Simulation Studies,-

   (1) Consideration of Voltage level,-
       For the purpose of planning of the STS System;
       a) The transmission network may be modeled down to 66kV level.
       b) The generating units that are stepped up at 110 kV may be connected at the nearest bus through 220/110 kV transformer for simulation purpose. STU may also consider modeling smaller generating units (below 25 MW capacity) within a plant by lumping them as a single unit, if required.

   (2) Time Horizons for Transmission Planning,-
       a) From concept to commissioning of transmission elements generally takes three to five years; about three years for augmentation of capacitors, reactors, transformers etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon.
b) Endeavour shall be to prepare base case models corresponding to load generation scenarios for a 5 year time horizon. These models may be tested applying the relevant criteria mentioned in the CEA manual.

27. **Load - Generation Scenarios,-**

The load-generation scenarios shall be worked out so as to reflect in a pragmatic manner the typical daily and seasonal variations in load demand and generation availability.

28. **Load demands,-**

(1) **Active Power (MW),-**

a) The system peak demands (State wise, regional and national) shall be based on the latest Electric Power Survey (EPS) report of CEA. However, the same may be moderated based on actual load growth of past three (3) years.

b) The load demands at other periods (seasonal variations and minimum loads) shall be derived based on the annual peak demand and past pattern of load variations. In the absence of such data, the season-wise variation in the load demand may be taken as given in the Table below:

<table>
<thead>
<tr>
<th>Sl. No</th>
<th>Season / Scenario</th>
<th>Demand Factor (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Summer peak Load (S-PL)</td>
<td>98</td>
</tr>
<tr>
<td>2</td>
<td>Summer Light Load (S-LL)</td>
<td>70</td>
</tr>
<tr>
<td>3</td>
<td>Monsoon peak Load (M-PL)</td>
<td>90</td>
</tr>
<tr>
<td>4</td>
<td>Monsoon Light Load (M-LL)</td>
<td>70</td>
</tr>
<tr>
<td>5</td>
<td>Winter Peak Load (W-PL)</td>
<td>100</td>
</tr>
<tr>
<td>6</td>
<td>Winter Light Load (W-LL)</td>
<td>70</td>
</tr>
</tbody>
</table>

(week 100% is for annual peak load).

c) While doing the simulation, if the peak load figures are more than the peaking availability of generation, the loads may be suitably adjusted substation wise to match with the availability. Similarly, while doing the simulation, if the peaking availability is more than the peak load, the generation despatches may be suitably reduced, to the extent possible, such that, the inter regional power transfers are high.
d) From practical considerations the load variations over the year shall be considered as under,-
   i) Annual Peak Load;
   ii) Seasonal variation in Peak Loads for Winter, Summer and Monsoon;
   iii) Seasonal Light Load (for Light Load scenario, motor load of Pumped storage plants shall be considered).

e) The substation wise annual load data, both MW and MVAR for peak and light load with voltage shall be provided by the state transmission/distribution utilities.

(2) **Reactive Power (MVAR),**

a) Reactive power plays an important role in EHV transmission system planning and hence forecast of reactive power demand on an area wise or substation wise basis is as important as active power forecast. This forecast would obviously require adequate data on the reactive power demands at the different substations as well as the projected plans for reactive power compensation.

b) For developing optimal STS, the STU shall use the substation wise maximum and minimum demand in MW and MVAR on seasonal basis. In the absence of such data the load power factor at 110kV and 66kV voltage levels may be taken as 0.95 lag during peak load condition and 0.98 lag during light load condition. The STU shall provide adequate reactive compensation at the substation level to bring power factor close to unity at 220kV, 110kV and 66kV voltage levels.

c) All generators and prosumers shall provide adequate voltage compensation as per grid requirements in both directions (lag and lead). The STU shall identify the requirement if reactive power injection and withdrawal at such nodes and intimate the generators/prosumers to provide adequate dynamic control in their system at the time of granting connectivity. Additional reactive requirements on account of generators/prosumers injecting power shall be to their account only.

29. **Generation Dispatches and Modeling,**

(1) For planning of new transmission lines and substations, the peak load scenarios corresponding to summer, monsoon and winter seasons may be studied. Further, the light load scenarios (considering pumping load where pumped storage stations exist) may also be carried out as per requirement.

(2) For evolving transmission systems for integration of wind and solar generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional Despatch scenarios. The maximum generation at a wind/solar aggregation level may be calculated using capacity factors, considering diversity in wind/solar generation (i.e.
the ratio of maximum generation available at an aggregation point to the algebraic sum of capacity of each wind machine/ solar panel connected to the grid point), as per the norms given in the Table below:

<table>
<thead>
<tr>
<th>Voltage level/ Aggregation level</th>
<th>110kV/ 66kV Individual Wind / Solar farm</th>
<th>220 kV</th>
<th>400 kV</th>
<th>State as a whole</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Factor %</td>
<td>80</td>
<td>75</td>
<td>70</td>
<td>60</td>
</tr>
</tbody>
</table>

(3) As per this Grid Code, it is the responsibility of SLDC to balance load and generation of the control area as a whole and stick to the schedules. Accordingly, it follows that in case of variation in generation from Renewable Energy Source (RES) portfolio, the SLDC shall instruct backing down/ ramping up its conventional (thermal/ hydro) generation plants or revise their drawal schedule from ISGS plants and any other source and stick to the revised schedule. The Intra State generating stations and the purchasing entities should be capable of ramping up/ backing down based on the directives from SLDC, so that the impact of variability in RES on the STS grid is minimized;
Provided that in case the technical minimum of the generators have been reached, SLDC may back down renewable sources also with reasons to be recorded.

(4) Further to address the variability of the Wind/ Solar projects, other aspects like reactive power compensation, forecasting and establishment of renewable energy control centers may also be planned by SLDC/ STU. Till such time, the renewable generators shall furnish the forecasted generation on day-ahead basis in accordance with the provisions for scheduling mentioned elsewhere in this document. The renewable generators shall also provide necessary reactive support in either direction as per the grid conditions at the point of coupling.

30. **Special Area Dispatches,-**

(1) Special Dispatches corresponding to high agricultural load with low power factor, wherever applicable.

(2) Complete closure of a generating station close to a major load centre.

(3) In case of thermal units (including coal, gas/ diesel and nuclear based) the minimum level of output (ex-generation bus, i.e., net of the auxiliary consumption) shall be taken as not less than 85% of the rated installed capacity. If the thermal units are encouraged to run with oil support, they may be modeled to run up to 55% of the rated capacity.
The generating unit shall be modeled to run as per their respective capability curves. In the absence of capability curve, the reactive power limits ($Q_{\text{max}}$ and $Q_{\text{min}}$) for generator buses may be taken as:

a) Thermal Units: $Q_{\text{max}} = 60\%$ of $P_{\text{max}}$ and $Q_{\text{min}} = (-) 50\%$ of $Q_{\text{max}}$.

b) Hydro Units: $Q_{\text{max}} = 48\%$ of $P_{\text{max}}$ and $Q_{\text{min}} = (-) 50\%$ of $Q_{\text{max}}$.

It shall be the duty of all the generators to provide technical details such as machine capability curves, generator, exciter, governor, PSS parameters etc., for modeling of their machines for steady state and transient state studies, in the format sought by STU.

31. Short circuit Studies,-

(1) The short circuit studies shall be carried out using the classical method with flat pre-fault voltages and sub-transient reactance ($X''d$) of the synchronous machines.

(2) MVA of all the generating units in a plant may be considered for determining maximum short circuit level at various buses in the system. This short circuit level may be considered for substation planning.

(3) Vector group of the transformers shall be considered for doing short circuit studies for asymmetrical faults. Inter-winding reactance in case of three winding transformers shall also be considered. For evaluating the short circuit levels at a generating bus (11kV, 13.8kV, 21kV etc.), the unit and its generator transformer shall be represented separately.

(4) Short circuit level both for three phase to ground fault and single phase to ground fault shall be calculated.

(5) The short circuit level in the system varies with operating conditions. It may be low for light load scenario compared with for peak load scenario, as some of the plants may not be on-bar. For getting an understanding of system strength under different load-generation/ export-import scenarios, the MVA of only those machines shall be taken which are on bar in that scenario.

32. Planning Margins,-

(1) In a very large interconnected grid, there can be unpredictable power flows in real time due to imbalance in load-generation balance in different pockets of the grid. This may lead to overloading of transmission elements during operation, which cannot be predicted in advance at the planning stage. This can also happen due to delay in commissioning of a few planned transmission elements, delay/ abandoning of planned generation additions or load growth at variance with the estimates. Such uncertainties are unavoidable and hence some margins at the planning stage may help in reducing impact of such uncertainties. However, care needs to be taken
to avoid stranded transmission assets. Therefore, at the planning stage following planning margins may be provided:

(2) Against the requirement of Long Term Access sought, the new transmission lines emanating from a power station to the nearest grid point may be planned considering overload capacity of the generating stations in consultation with generators.

(3) The new transmission additions required for system strengthening may be planned keeping a margin of 10% in the thermal loading limits of lines and transformers.

(4) At the planning stage, a margin of about +/- 2% may be kept in the voltage limits and thus the voltages under load flow studies (for ‘N-0’ and ‘N-1’ steady state conditions only) may be maintained within the limits given below:

<table>
<thead>
<tr>
<th>Voltage (kV rms) (after planning margins)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal</td>
</tr>
<tr>
<td>---------</td>
</tr>
<tr>
<td>765</td>
</tr>
<tr>
<td>400</td>
</tr>
<tr>
<td>220</td>
</tr>
<tr>
<td>110</td>
</tr>
<tr>
<td>66</td>
</tr>
</tbody>
</table>

(5) In planning studies all the transformers may be kept at nominal taps and On Load Tap Changer (OLTC) may not be considered. The effect of the taps should be kept as operational margin.

(6) For the purpose of load flow studies at planning stage, the nuclear generating units shall normally not run at leading power factor. To keep some margin at planning stage, the reactive power limits \((Q_{\text{max}} \text{ and } Q_{\text{min}})\) for generator buses may be taken as:

<table>
<thead>
<tr>
<th>Type of generator</th>
<th>(Q_{\text{max}})</th>
<th>(Q_{\text{min}})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>(0.5 \times P_{\text{max}})</td>
<td>((-0.10 \times P_{\text{max}})</td>
</tr>
<tr>
<td>Thermal</td>
<td>(0.5 \times P_{\text{max}})</td>
<td>((-0.10 \times P_{\text{max}})</td>
</tr>
<tr>
<td>Hydro</td>
<td>(0.4 \times P_{\text{max}})</td>
<td>((-0.20 \times P_{\text{max}})</td>
</tr>
</tbody>
</table>

(7) Notwithstanding above, during operation, following the instructions of the System Operator, the generating units shall operate at leading power factor as per their respective capability curves.
Additional Planning Criteria and Guidelines (33 to 40)

33. **Reactive Power Compensation**
   Requirement of reactive power compensation like Shunt Capacitors, Shunt Reactors (bus reactors or line reactors), Static VAR Compensators, Fixed Series Capacitor, Variable Series Capacitor (thyristor controlled) or other FACTS devices shall be assessed by appropriate studies.

34. **Shunt Capacitors**
   (1) Reactive compensation shall be provided as far as possible in the low voltage systems with a view to meet the reactive power requirements of load close to the load points, thereby avoiding the need for VAR transfer from high voltage system to the low voltage system. In the cases where network below 110 kV/ 220 kV voltage level is not represented in the system planning studies, the shunt capacitors required for meeting the reactive power requirements of loads shall be provided at the 110kV/ 220kV buses for simulation purpose.

   (2) It shall be the responsibility of the respective distribution licensees to bring the load power factor as close to unity as possible by providing shunt capacitors at appropriate places in their system. Reactive power flow through 400/ 220 kV or 220/ 110 (or 66) kV ICTs shall be minimal. Wherever voltage on HV side of such an ICT is less than 0.975 pu, no reactive power shall flow down through the ICT. Similarly, wherever voltage on HV side of the ICT is more than 1.025 pu, no reactive power shall flow up through the ICT. These criteria shall apply under the ‘N-0’ conditions.

35. **Shunt Reactors**
   (1) Switchable bus reactors shall be provided at EHV substations for controlling voltages within the limits specified in Regulation 20 without resorting to switching off of lines. The bus reactors may also be provided at generation switchyards to supplement reactive capability of generators. The size of reactors should be such that under steady state condition, switching on and off of the reactors shall not cause a voltage change exceeding 5%.

   (2) Fixed line reactors may be provided to control power frequency temporary over voltage (TOV) after all voltage regulation action has taken place within the limits as defined in Regulation 20(b) under all probable operating conditions.

   (3) Line reactors (switchable/ controlled/ fixed) may be provided if it is not possible to charge EHV line without exceeding the maximum voltage limits given in Regulation 20(a). The possibility of reducing pre-charging voltage
of the charging end shall also be considered in the context of establishing
the need for reactors.

(4) Guideline for Switchable line Reactors,
- The line reactors may be planned as switchable, wherever the voltage
limits without the Reactors remain within limits specified for TOV
conditions given at Regulation 20(b).

36. Static VAR Compensation (SVC),
- Static VAR Compensation (SVC) shall be provided where found necessary
to damp the power swings and provide the system stability under
conditions defined in Regulations 22 to 24 on ‘Reliability Criteria’. The
dynamic range of static compensators shall not be utilized under steady
state operating condition, as far as possible.

37. Substation Planning Criteria,
(1) The requirements in respect of EHV substations in a system such as the
total load to be catered by the substation of a particular voltage level, its
MVA capacity, number of feeders permissible etc., are important to the
planners so as to provide an idea to them about the time for going in for the
adoption of next higher voltage level substation and also the number of
substations required for meeting a particular quantum of load. Keeping
these in view the following criteria have been laid down for planning an
EHV substation:
(2) The maximum short circuit level on any new substation bus should not
exceed 80% of the rated short circuit capacity of the substation. The 20%
margin is intended to take care of the increase in short circuit levels as the
system grows.
(3) The rated breaking current capability of switchgear at different voltage
levels may be taken as given below:

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>Rated Breaking Capacity</th>
<th>Max. Rated Breaking Time</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>(for 1 sec)</td>
<td>(in milli seconds)</td>
</tr>
<tr>
<td>66 kV</td>
<td>25kA/ 31.5kA</td>
<td>100 ms</td>
</tr>
<tr>
<td>110 kV</td>
<td>25kA/ 31.5kA</td>
<td>100 ms</td>
</tr>
<tr>
<td>220 kV</td>
<td>31.5kA/ 40kA</td>
<td>60 ms</td>
</tr>
<tr>
<td>400 kV</td>
<td>50kA/ 63kA</td>
<td>40 ms</td>
</tr>
<tr>
<td>765 kV</td>
<td>40kA/ 50kA</td>
<td>40 ms</td>
</tr>
</tbody>
</table>

(4) Measures such as splitting of bus, series reactor, or any new technology
may also be adopted to limit the short circuit levels at existing substations
wherever they are likely to cross the designed limits, without sacrificing the
operational flexibility and grid security.
(5) Rating of the substation equipments such as Power Transformers,
Capacitors, Shunt Reactors, Circuit Breakers, Disconnectors and Earthing
Switches, CTs, VTs, Surge Arrestors, Line Traps, Insulators etc, shall be such that they do not limit the loading limits of connected transmission lines and should satisfy the Technical Particulars and requirements specified under *Chapter IV of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010*.

(6) Effort should be to explore possibility of planning a new substation instead of adding transformer capacity at an existing substation when the capacity of the existing substation has reached levels as given in column (B) in the table below. The capacity of any single substation at different voltage levels shall not normally exceed as given in column(C) in the Table:

<table>
<thead>
<tr>
<th>Voltage Level (A)</th>
<th>Existing capacity (B)</th>
<th>Maximum Capacity (C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>765 kV</td>
<td>6000 MVA</td>
<td>9000 MVA</td>
</tr>
<tr>
<td>400 kV</td>
<td>1260 MVA</td>
<td>2000 MVA</td>
</tr>
<tr>
<td>220 kV</td>
<td>320 MVA</td>
<td>500 MVA</td>
</tr>
<tr>
<td>110 kV</td>
<td>150 MVA</td>
<td>250 MVA</td>
</tr>
<tr>
<td>66 kV</td>
<td>50 MVA</td>
<td>75 MVA</td>
</tr>
</tbody>
</table>

(7) While augmenting the transformation capacity at an existing substation or planning a new substation the fault level of the substation shall also be kept in view. If the fault level is low the voltage stability studies shall be carried out.

(8) Size and number of interconnecting transformers (ICTs) shall be planned in such a way that the outage of any single unit would not overload the remaining ICT(s) or the underlying system.

(9) A stuck breaker condition shall not cause disruption of more than four feeders for the 220kV system and two feeders for the 400kV system and 765kV system. For this the following bus switching scheme may be adopted for both AIS and GIS and also for the generation switchyards,-

- 66 kV and 110 kV – ‘Main and Transfer bus’ or Double bus scheme.
- 220kV – ‘Double Main’ or ‘Double Main and Transfer’ Bus scheme with maximum of eight (8) feeders in one section.
- 400kV and 765kV -- ‘One and half breaker’ Bus scheme.
(10) Additional Norms,-

a) The capacity of ICTs in a substation at a voltage level shall be kept as same.

b) The firm capacity (MVA) of a substation at a voltage level shall be taken as 110% X (N-1) of single transformer capacity (3 phase), where N is the number of transformers.

c) New substations shall be planned as standard three transformer configuration, with two Bus. Minimum two transformers shall be commissioned during the initial stages.

d) The transformer capacity at each voltage level shall be standardized enabling up gradation of substation capacity by replacing the transformers with higher capacity in the same plinth.

e) The substations shall be located at places where the ground level is above the maximum flood level recorded in the area.

f) The standard capacity of ICTs in the substations in Kerala at each voltage level shall be;

<table>
<thead>
<tr>
<th>Voltage Level</th>
<th>110kV</th>
<th>220kV</th>
<th>400kV</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>12.5/16/ 20/ 30 MVA</td>
<td>100/ 200/ 315 MVA</td>
<td>315/ 500 MVA</td>
</tr>
</tbody>
</table>

g) The Reactance of the transformers planned (Xt at own base MVA) shall be,-

- Generator Transformers : 14 – 15%
- ICT : 12.5%

38. Additional Criteria for Wind and Solar projects,-

(1) The capacity factor for the purpose of maximum injection to plan the evacuation system both for immediate connectivity with the STS and for onward transmission requirement may be taken as given below,-

<table>
<thead>
<tr>
<th>Voltage level/ Aggregation level</th>
<th>110kV/66kV/ Individual Wind/ Solar farm</th>
<th>220kV</th>
<th>400kV</th>
<th>State as a whole</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity Factor %</td>
<td>80</td>
<td>75</td>
<td>70</td>
<td>60</td>
</tr>
</tbody>
</table>

(2) The ‘N-1’ criteria may not be applied to the immediate connectivity of Wind/ Solar farms with the STS grid i.e. the line connecting the farm to the grid and the step up transformers at the grid station.

(3) The Wind generating stations connected at voltage level of 66kV and above shall remain connected to the grid when the voltage at the interconnection point or any or all phases dips to a level of 85% of the nominal voltage (i.e. the wind generators should be capable to have low voltage ride through (LVRT) and High Voltage Ride Through (HVRT) facility).
As the generation of energy at a wind farm is possible only with the prevalence of wind, the thermal line loading limit of the lines connecting the wind machine(s)/farm to the nearest grid point may be assessed considering 12km/hour wind speed.

The Wind and Solar farms shall maintain a power factor of 0.98 (absorbing) at their grid interconnection point for all Despatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies. The generators shall operate in such a way as to provide required reactive power support at the point of connection with the grid. If the voltage at the point of connection is less than the rated voltage, the wind/solar generator shall inject reactive power and vice versa. Those generators which are not capable of providing reactive support in both directions as per the voltage at the point of connection shall make necessary changes in their system within a period of one year from the date of implementation of these Regulations.

The Harmonic current injection from a generating station shall not exceed the limits specified in IEEE standard 519. The THD for voltage at the connection point shall not exceed 5% with no individual harmonic higher than 3% and the THD for current drawn from the transmission system at the connection point shall not exceed 8%.

39. **Guidelines for Voltage Stability Studies**

   (1) These studies may be carried out using load flow analysis program by creating a fictitious synchronous condenser at critical buses which are likely to have wide variation in voltage under various operating conditions i.e. bus is converted into a PV bus without reactive power limits. By reducing desired voltage of this bus, MVAR generation/absorption is monitored. When voltage is reduced to some level it may be observed that MVAR absorption does not increase by reducing voltage further, instead it also gets reduced. The voltage where MVAR absorption does not increase any further is known as Knee Point of Q-V curve. The knee point of Q-V curve represents the point of voltage instability. The horizontal 'distance' of the knee point to the zero MVAR vertical axis measured in MVAR is, therefore, an indicator of the proximity to the voltage collapse.

   (2) Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions as discussed above. The system shall have adequate margins in terms of voltage stability.
40. **Guidelines for consideration of Zone - 3 settings,**

In some transmission lines, the Zone -3 relay setting may be such that it may trip under extreme loading condition. The transmission utilities should identify such relay settings and reset it at a value so that they do not trip at extreme loading of the line. For this purpose, the extreme loading may be taken as 120% of thermal current loading limit and assuming 0.9 per unit voltage. In case it is not practical to set the Zone-3 in the relay to take care of above, the transmission licensee/ owner shall inform STU and SLDC along with setting (primary impendence) value of the relay. Mitigating measures shall be taken at the earliest and till such time the permissible line loading for such lines would be the limit as calculated from relay impedence assuming 0.95 pu voltage, provided it is permitted by stability and voltage limit considerations as assessed through appropriate system studies.

41. **Planning Data,**

1. To enable STU to conduct System Studies and prepare perspective plans for electricity demand, generation and transmission, the Users shall furnish data, to STU from time to time as detailed under Data Registration section as under,
   - (i) Standard Planning Data (Generation)/ Standard Planning Data (Distribution) as per Appendix- A1/ A3;
   - (ii) Detailed Planning Data (Generation)/ Detailed Planning Data (Distribution) as per Appendix – B1/ B3.

2. To enable the users to co-ordinate planning, design and operation of their plants and systems with the State Transmission System, they may seek certain salient data of Transmission System as applicable to them, which STU shall supply from time to time as detailed under Data Registration section and categorized as:
   - (i) Standard Planning Data (Transmission) as per Appendix- A2;
   - (ii) Detailed Planning Data (Transmission) as per Appendix- B2.

3. STU shall also furnish to all the Users, Annual Transmission Planning Report, Power Map and any other information as the Commission may specify.

42. **Implementation of Transmission Plan,**

The actual program of implementation of transmission lines, ICTs, Reactors/ Capacitors and other transmission elements will be in accordance with the detailed procedures mentioned in the CERC (Grand of connectivity, long term access and medium term open access in ISTS and related matters) Regulations, 2009, KSERC (Connectivity and Intra State Open Access) Regulations, 2013, Kerala Electricity Supply Code, 2014 and this State Grid Code, as amended from time to time.
Part III

GRID CONNECTIVITY CONDITIONS

43. Connectivity Conditions.-

(1) Connectivity Conditions specify the minimum technical, design and operational criteria which must be complied with by STU and every User connected to or seeking connection to the State Transmission System. These also set out the procedure by which STU shall ensure compliance by any agency with above criteria as pre-requisite for establishment of an agreed connection. STU and other Users connected to or seeking connection to STS shall comply with CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007; Grid Standards Regulation, 2010 and KSERC (Connectivity and Intra State Open Access) Regulations, 2013 as amended from time to time.

(2) The objective of this part is to ensure the following:-

(i) All Users or prospective Users are treated equitably and to ensure the safe operation, integrity and reliability of the Grid;

(ii) Any new or modified connection, when established, shall not impose any adverse effect on STS, nor shall a new or modified connection suffer adversely due to its connectivity to STS;

(iii) By specifying minimum design and operational criteria, to assist Users in their requirement to comply with License obligations and to ensure that a system of acceptable quality is maintained;

(iv) The ownership and responsibility for all items of equipment is clearly specified in a schedule (Appendix D: Site Responsibility Schedule) for every site where a Connection is made.

(3) Procedure for Application.-

The procedure for any new connection or modification of an existing connection with the State Transmission System shall consist of the following:-

Any User seeking to establish new or modified arrangements for connection to and/or use of the transmission system shall submit the following report, data and undertaking along with an application and processing fee to the STU/ Transmission licensee:-

(a) Report stating purpose of proposed connection and/or modification, connection site, transmission licensee to whose system connection is proposed, description of apparatus to be connected or modification to apparatus already connected and beneficiaries of the proposed connection;

(b) Construction schedule and target completion date;

(c) An undertaking that the user shall abide by the provisions of KSGC, IEGC, Electricity Act/ Rules, Safety Rules and relevant Standards including Grid Connectivity Standards made by the Authority pursuant to the Act for installation and operation of the apparatus;
(d) The User shall furnish the Detailed Planning Data as per Appendix B;
(e) For special loads like arc furnaces, rolling mills etc., Active and Reactive Power values of the load with time and harmonic level.

(4) STU shall process the application for grant of connectivity in accordance with KSERC (Connectivity and Intra State Open Access) Regulations, 2013 and make a formal offer within 60 days of the receipt of the application. The offer shall specify and take into account any works required for the extension or reinforcement of the State Transmission System necessitated by the applicant’s proposal and for obtaining any consent necessary for the purpose.

(5) If the specified time limit for making the offer against any application is not adequate, STU shall make a preliminary offer within the specified time indicating the extent of further time required for detailed analysis.

(6) Any offer made by STU shall remain valid for a period of 60 days and unless accepted before the expiry of such period, shall lapse thereafter.

(7) In the event of offer becoming invalid or not accepted by the applicant, alternative offer or revised application can be furnished with processing fee and the procedure laid above will be followed.

44. Rejection of Application.-
The STU shall be entitled to reject any application for connection to or use of the State Transmission System due to the following reasons apart from others as considered reasonable:
(1) If such proposed connection is likely to cause breach of any provision of its License or any provision of the State Grid Code or any provision of IEGC or any criteria or covenants or deeds or regulations by which STU is bound;
(2) If the applicant does not undertake to be bound, in so far as applicable, by the terms of the State Grid Code;
(3) If the applicant fails to give confirmation and undertakings according to this Section.

45. Connection Agreement.-
(1) A Connection Agreement (or the offer for a Connection Agreement) shall include within its terms and conditions the following:-
(i) A condition requiring both the agencies to comply with the State Grid Code;
(ii) Details of connection charges and/or use of system charges;
(iii) Details of any capital related payments arising from necessary reinforcement or extension of the system, Data Communication, RTU etc. and its demarcation;
(iv) Diagram of electrical system to be connected;
(v) General philosophy, guidelines and requirements on Protection, Telemetry, Harmonics, DC injection, Flicker etc;
(vi) A Site Responsibility Schedule (Appendix D).

(2) A Connection Agreement with the above terms and conditions, not inconsistent with CEA (Technical Standards for connectivity to the Grid) Regulations, 2007 and KSERC (Connectivity and Intra State Open Access) Regulations, 2013 shall be signed by the applicant with STU.
46. **Site Responsibility Schedule,**
For every Connection to the State Transmission System for which Connection Agreement is required, STU shall prepare a schedule of equipments with information supplied by the respective Users. This schedule, called a Site Responsibility Schedule (Appendix D), shall indicate the following for each item of equipment installed at the Connection site,-

(i) The ownership of equipments;
(ii) The responsibility for control of equipments;
(iii) The responsibility for maintenance of equipments;
(iv) The responsibility for operation of equipments;
(v) The management of the site;
(vi) The responsibility for all matters relating to safety of persons and equipments at the site.

47. **System Performance,**

(1) All equipments connected to the State Transmission System shall be of such design and construction that enables STU to meet the requirements of Standards of Performance. Distribution Licensees and other Users shall ensure that their loads do not cause violation of these standards.

(2) Any User seeking to establish new or modified arrangement(s) for Grid connection and/or use of transmission system of STU shall submit the application in the form as specified by STU.

(3) For every new/ modified Connection sought, STU shall specify the Connection Point, technical requirements and the voltage to be used, along with the metering and protection requirements as specified in the Metering Code and Protection Code.

(4) All the Generators shall make available to SLDC the up to date capability curves for all Generating Units, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System.

(5) The State Transmission System rated frequency shall be 50.00 Hz and shall always remain within the 49.9 -50.2 Hz band or as specified in IEGC.

(6) The User shall be subject to the Grid discipline in respect of variation of voltage at the inter connection point prescribed by clause 3(1) (b) of the CEA Grid Standards, as shown below;

<table>
<thead>
<tr>
<th>Nominal (kV)</th>
<th>Maximum (kV)</th>
<th>Minimum (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>765</td>
<td>800</td>
<td>728</td>
</tr>
<tr>
<td>400</td>
<td>420</td>
<td>380</td>
</tr>
<tr>
<td>220</td>
<td>245</td>
<td>198</td>
</tr>
<tr>
<td>110</td>
<td>121</td>
<td>99</td>
</tr>
<tr>
<td>66</td>
<td>72</td>
<td>60</td>
</tr>
<tr>
<td>33</td>
<td>36</td>
<td>30</td>
</tr>
</tbody>
</table>
(7) Distribution Licensees and Open Access/ EHV Consumers directly connected to STS shall ensure that their loads do not affect STU system in terms of causing any,-

(i) Unbalance in the phase angle and magnitude of voltage at the interconnection point beyond the limits prescribed.

(ii) Individual and Total Harmonic Distortion (THD) of voltage shall not exceed the values specified in clause 3(2) of the CEA Grid Standards, as shown below;

<table>
<thead>
<tr>
<th>System Voltage (kV)</th>
<th>Total Harmonic Distortion (THD)</th>
<th>Individual harmonic of any particular frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>765</td>
<td>1.5%</td>
<td>1.0%</td>
</tr>
<tr>
<td>400</td>
<td>2.0%</td>
<td>1.5%</td>
</tr>
<tr>
<td>220</td>
<td>2.5%</td>
<td>2.0%</td>
</tr>
<tr>
<td>33 to 110</td>
<td>5.0%</td>
<td>3.0%</td>
</tr>
</tbody>
</table>

STU may direct the Distribution Licensees and Open Access/ EHV Consumers connected to STS to take appropriate measures to bring the Harmonics within the permissible limits.

(8) In the event of Grid disturbances in the Southern Regional grid, STU shall not be liable to maintain the system parameters within the normal range of voltage and frequency.

48. Standards and Codes of Practice,-

(1) The user shall follow the industry best practices and applicable Industry standards in respect of the equipment installation and its operation and maintenance.

(2) The equipments including overhead lines and cables shall comply with the relevant Indian Standards or International Electro technical Commission (IEC) Standards or ANSI Standards or any other equivalent International standards.

(3) The effects of wind, storms, floods, lightning, elevation, Temperature extremes, icing, contamination, pollution and Earthquakes must be considered in the design and operation of the connected facilities.

(4) Installation, operation and maintenance of the equipment by user shall conform to the relevant standards specified by the authority under Section 177 and Section 73 of the Act.
49. **Safety Standards and Responsibility,**
STU and the users shall be responsible for safety and shall comply with the CEA (Measures Relating to Safety and Electric Supply) Regulations, 2010 and other applicable safety standards for construction, operation and maintenance of Electrical systems.

50. **Substation Grounding,**
Each Transmission substation must have a ground mat solidly connected to all metallic structures and other non energized metallic equipment. The earth mat shall limit the ground potential gradients to such voltage and current levels that will not endanger the safety of people or damage equipments which are in or immediately adjacent to the station under normal and fault conditions. The ground mat size and type shall be based on local soil conditions and available electrical fault current magnitudes. Areas where ground mat voltage rises would not be within acceptable and safe limits (for example due to high soil resistively or limited substation space), grounding rods and ground wells may be used to reduce the ground grid resistance to acceptable levels. Substation grounding shall be done in accordance with the norms of the Institute of Electrical and Electronics Engineers (IEEE) Standard 80.

51. **Metering,**
Meters shall be provided by the consumers/ generating company/ Distribution licensee/ Traders, as specified in the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006 and KSERC (Connectivity and Intra State Open Access) Regulations, 2013, as amended from time to time.

52. **Basic Insulation Level and Insulation Coordination,**

1. Basic Insulation Level (BIL) of various items of equipment and rating of Surge arresters for generating stations, lines and substations shall be decided on the following order of priority, namely:
   (a) Ensuring safety to public and operating personnel;
   (b) Avoiding permanent damage to plant;
   (c) Preventing failure of costly equipment;
   (d) Minimizing circuit interruptions;
   (e) Minimizing interruptions of power supply to consumers.

2. Insulation Coordination of equipment and lines on both sides of a Connection point belonging to the user and the grid shall be accomplished and the coordination shall be done by the State Transmission Utility.
53. Protection system and Coordination,-

(1) Protection system shall be designed to reliably detect faults on various abnormal conditions and provide means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as equipment failures or open phase conditions.

(2) Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity. Where failure of protective relay in the user’s system has substantial impact on the grid, it shall connect an additional protection as back up protection, besides the main protection.

(3) Notwithstanding the protection systems provided in the grid, the user shall provide requisite protections for safeguarding his system from the faults originating in the grid.

(4) Bus bar protection and breaker fail protection or Local Breaker Backup protection shall be provided wherever stipulated in the Regulations.

(5) Special Protection Scheme such as under frequency relay for load shedding, Voltage instability, angular instability, generation backing down or islanding schemes may also be required to be provided to avert system disturbances.

(6) Protection Coordination issues shall be finalized by STU and SLDC.

(7) User shall develop protection manuals conforming to various standards, for the reference and use of its personnel.

54. Schematic Diagrams,-

The User shall prepare single line schematic diagrams in respect of its system facility and make the same available to the State Transmission Utility through which his system is connected and to SLDC.

55. Inspection, Test, Calibration and Maintenance prior to connection,-

Before connecting, the user shall complete all inspections and tests finalized in consultation with the State Transmission Utility to which his equipment is connected. The user shall make available all drawings, specifications and test records of the project/generating station, as the case may be, to the STU.

56. Grid Connectivity Standards applicable to State Generating Units,-

(1) The generating units of a user proposed to be connected to the grid shall comply with the following requirements also, besides the general connectivity conditions and requirements given in the Regulations 47 to 55 above.

(2) The excitation system for every generating unit,-
(a) Shall have state of the art excitation system;
(b) Shall have Automatic Voltage Regulator (AVR). Generators of 100MW rating and above shall have Automatic Voltage Regulator with digital control and two separate channels having independent inputs and automatic changeover;
(c) The Automatic Voltage Regulator of generator of 100 MW and above shall include Power System Stabilizer (PSS).

(3) The short circuit ratio (SCR) for generators shall be as per IEC 34.
(4) The Generator transformer windings shall have delta connection on low voltage side and star connection on high voltage side. Star point of high voltage side shall be effectively (solidly) earthed, so as to achieve the Earth Fault Factor of 1.4 or less.
(5) All Generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal Generating units shall have a droop of 3 to 6% and those of hydro generating units 0 to 10%.
(6) The project of the user shall not cause Voltage and Current harmonics on the grid which exceed the limits specified in Institute of Electrical and Electronics Engineers (IEEE) Standard 519.
(7) Generating units shall be capable of operating at rated output for power factor varying between 0.85 lagging (over-excited) to 0.95 leading (under-excited). The above performance shall also be achieved with voltage variation of +/- 5% of nominal, frequency variation of +3% and -5% and combined voltage and frequency variation of +/- 5%. However, for gas turbines, the above performance shall be achieved for voltage variation of +/- 5%.
(8) The coal and lignite based thermal generating units shall be capable of generating up to 105% of Maximum Continuous Rating (subject to maximum load capability under Valve Wide Open Condition) for short duration to provide the frequency response.
(9) The hydro generating units shall be capable of generating upto 110% of MCR (subject to rated head being available) on continuous basis.
(10) Hydro generating units having capacity of 50 MW and above shall be equipped with facility to operate in synchronous condenser mode, wherever feasible and if the same is established by the Interconnection studies.
(11) Hydro generating units shall have Black Start facilities as specified in the CEA Technical Standards Regulations.
(12) Every generating unit shall have standard protections to protect the units not only from faults within the units and within the station, but also from faults in transmission line. For generating units having rated capacity greater than 100 MW two independent sets of protections acting on two independent sets of trip coils fed from independent Direct Current (DC) supplies shall be provided. The protections shall include but not be limited to the Local Breaker Backup (LBB) protection.
(13) Bus bar protection shall be provided at the switchyard of all Generating stations.
Automatic Synchronization facilities shall be provided by the user.

The station auxiliary power requirement, including voltage and reactive requirements shall not impose operating restrictions on the grid beyond those specified in the Grid Code or State Grid Code as the case may be.

The Wind generating stations, Generating stations using Inverters and Wind-Solar photo voltaic hybrid systems shall additionally comply with the following requirements:

- a) The Harmonic current Injection from the station shall not exceed the limits specified in the IEEE Standard 519;
- b) The Generating station shall not inject DC current >0.5% of the full rated output at the Interconnection Point;
- c) The Generating station shall not introduce flicker beyond the limits specified in IEC 61000 standard;
- d) Measurement of Harmonic content, DC injection and flicker shall be done at least once in a year in the presence of the parties concerned and the indicative date for the same shall be mentioned in the Connection Agreement;
- e) The Generating station shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits of 0.95 lagging to 0.95 leading;
- f) The Generating unit shall be capable of operating in the frequency range of 47.5 Hz to 52 Hz and be able to deliver rated output in the frequency range of 49.5 Hz to 50.5 Hz;
  Provided that in the frequency range below 49.90 Hz and above 50.05 Hz, or as prescribed by the Commission from time to time, it shall be possible to activate the control system to regulate the output of the generating unit as per frequency response requirement as provided in sub clause (h) below:
  Provided further that the generating unit shall be able to maintain its performance contained in this sub clause even with voltage variation of upto +/- 5%, subject to availability of commensurate wind speed in case of wind generating stations and Solar insolation in case of Solar generating stations;
- g) The generating station connected to the grid, shall remain connected to the grid when voltage at the interconnection point on any or all phases dips upto the levels depicted in the CEA Grid connectivity Regulations 2019, Part II, clause B2(3);
  Provided that during the voltage dip, the supply of reactive power has priority, while the supply of active power has second priority and the active power preferably be maintained during power drops, provided, a reduction in active power within the plant’s design specifications is acceptable and the active power be restored to at least 90% of the pre-fault level within 1 sec of restoration of voltage;
- h) The generating stations with installed capacity of more than 10 MW connected at 33 kV and above,-
  (i) shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions of the SLDC;
(ii) shall have governors or frequency controllers of the units at a droop of 3 to 6% and a dead band not exceeding +/-0.03%;

Provided that for frequency deviations in excess of 0.3Hz, the generating station shall have the facility to provide an immediate (within 1 second) real power primary frequency response of at least 10% of the maximum Alternating Current active power capacity;

(iii) shall have the operating range of the frequency response and regulation system from 10% to 100% of the maximum AC active power capacity, corresponding to solar insolation or wind speed, as the case may be;

(iv) shall be equipped with the facility for controlling the rate of change of power output at a rate not more than +/- 10% per minute.

i) The generating station connected to the grid, shall remain connected to the grid when voltage at the interconnection point, on any or all phases (symmetrical or asymmetrical overvoltage conditions) rises above the specified values given below for specified time,-

<table>
<thead>
<tr>
<th>Over voltage (pu)</th>
<th>Minimum time to remain connected (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.30&lt;V</td>
<td>0 sec (instantaneous trip)</td>
</tr>
<tr>
<td>1.30 &gt;/= V &gt;1.20</td>
<td>0.2 sec</td>
</tr>
<tr>
<td>1.20 &gt;/= V&gt;1.10</td>
<td>2.0 sec</td>
</tr>
<tr>
<td>V&lt;/=1.10</td>
<td>continuous</td>
</tr>
</tbody>
</table>

j) Short Circuit Ratio at the interconnection point where the generating resource is proposed to be connected shall not be less than 5.

57. **Grid Connectivity Standards applicable to Transmission Lines and Substations,**

(1) The Transmission lines and Substations to be connected to the grid shall comply with the following requirements besides the general connectivity conditions and requirements given in the Regulations 47 to 55 above.

(2) All substations of and above 220 kV voltage level shall be provided with Bus bar protection and Local Breaker Backup (LBB) protection.

(3) Two Main Numerical Distance Protection Schemes shall be provided in the Substations on all the Transmission lines of 220 kV and above.

(4) Circuit breakers, Isolators and all other current carrying equipments shall be capable of carrying normal and emergency load currents without damage and shall not become a limiting factor for power transfer on the transmission lines.

(5) All Circuit breakers and fault interrupting devices shall be capable of safely interrupting fault currents for any faults they are required to interrupt, without the use of intentional time delay in clearing the fault.

(6) The Circuit Breakers shall have the capability and shall perform,-

a) Without the use of intentional time delay in clearing the fault;

b) all other switching duties such as, but not limited to, capacitive current switching, load current switching and out of step switching;

c) all required duties without creating transient over voltages that could damage the equipments provided elsewhere in the grid;
d) The short circuit capacity shall be based on short term and perspective Transmission plans finalized.

58. **Power Supply to Auxiliaries of Substation shall be,—**

   a) **AC Supply:**
      
      i) **220 kV and above:** Two HT supplies (one source standby to the other) shall be arranged from Independent sources. Additionally, an emergency supply from Diesel Generating (DG) source of suitable capacity shall also be provided.
      
      ii) **66kV and 110kV:** There shall be one HT supply and one Diesel Generating source.
      
      iii) **33 kV:** There shall be one HT supply.

   b) **DC Supply:**
      
      i) **Above 110 kV and Substations of all Generating stations:** There shall be two sets of batteries, each equipped with its own charger.
      
      ii) **110kV and below:** There shall be one set of battery and charger.

   c) **Earth Fault Factor of an effectively earthed system shall not be >1.4.**

59. **Grid Connectivity Standards applicable to the Distribution Systems and Bulk Consumers,—**

   The following additional requirements shall be complied with, besides the general connectivity conditions and requirements given in the Regulations 47 to 55 above:

   (1) **Under Frequency/ df/dt Relays,—**

      Under Frequency and df/dt (rate of change of frequency with time) relays shall be employed for automatic load control in a contingency to ensure grid security under conditions of falling grid frequency, as per the directions of SPCC/ SLDC.

   (2) **Automatic Demand Management System (ADMS),—**

      All substations including the substations of the consumers and prosumers shall provide equipments to receive ADMS (Automatic Demand Management System) signals from SLDC and shall identify designated feeders for load relief in case of operation of the ADMS.

   (3) **Reactive Power,—**

      The power factor of the distribution system and the bulk consumers shall be within +/- 0.95. The distribution licensees and the bulk consumer shall provide adequate reactive compensation to compensate reactive power requirements in their system, so that they do not depend upon the grid for reactive power support.

   (4) **Voltage and Current Harmonics,—**

      a) The limits of voltage harmonics by the distribution licensee in its electricity system, the limits of injection of current harmonics by bulk
consumers, point of harmonic measurement, i.e. point of common
coupling, method of harmonic measurement and other related
matters, shall be in accordance with the IEEE 519-2014 standards, as
amended from time to time;
b) Measuring and metering of harmonics shall be continuous process
with meters complying with provisions of IEC 61000-4-30 Class A;
c) The data with regard to the harmonics measured and metered as in
clause (b) above, shall be available with distribution licensee and shall
also be shared with the consumer periodically;
d) The bulk consumer shall install power quality meter and share the
recorded data thereof with the distribution licensee with such
periodicity as specified by the Commission;
e) In addition to harmonics, period measurement of other power quality
parameters such as voltage sag, swell, flicker, disruptions etc., as per
relevant IEC standards, shall be done by the distribution licensee and
the reports thereof shall be shared with the consumer;
f) The distribution licensee shall install power quality meters in a phased
manner, in the 33 kV substations.

(5) Voltage Unbalance,-
The voltage unbalance at 33 kV and above shall not exceed 3%.

(6) Voltage Fluctuations,-
a) The voltage fluctuations for step changes which may occur repetitively
shall not exceed 1.5%.
b) The voltage fluctuations for occasional fluctuations, other than step
changes, shall not exceed 3%.

(7) Back Energization,-
The Bulk consumer shall not energize transmission or distribution
system by injecting supply from his generators or any other source
either by automatic controls or manually unless specifically provided for
in the connection agreement with the Transmission or Distribution
Licensee.

60. In addition to the above all the terms and conditions mentioned in the
Central Electricity Authority (Technical Standards for connectivity to the
Grid) Regulations, 2007 and amendments thereof shall be binding to and
shall fulfill all the criteria mentioned.

61. Reactive Power Compensation,-
(1) Reactive Power compensation and/or other facilities shall be provided by
Users connected to STS as far as possible in the low voltage system close
to the load points, thereby avoiding the need for exchange of reactive
power to/from STS and to maintain STS voltage within the specified range.

(2) The users already connected to the grid shall also provide additional
reactive compensation as per the quantum and time frame decided by
SLDC. The Users/ Transmission Licensees/ Distribution Licensees shall provide information to SLDC regarding the installation and healthiness of the reactive compensation equipment on regular basis. SLDC shall regularly monitor the status in this regard.

62. **Data and Communication Facilities,**

   Reliable and efficient speech and data communication systems shall be provided to facilitate necessary communication and data exchange, and supervision/ control of the grid by the SLDC, under normal and abnormal conditions. All Users shall provide Systems to telemeter power system parameters such as power flow, voltage and status of switches/ transformer taps etc. in line with interface requirements and other guidelines made available by SLDC. The associated communication system to facilitate data flow upto appropriate data collection point on STU’s system shall also be established by the concerned User as specified by STU in the Connection Agreement. All Users in coordination with STU shall provide the required facilities at their respective ends as specified in the Connection Agreement.

63. **System Recording Instruments,**

   Every generating station and substation connected to the grid at 220 kV and above shall be provided with disturbance recorder and event logging facilities. All such equipments shall be provided with time synchronization facility for global common time reference. Recording instruments such as Data Acquisition System/ Disturbance Recorder/ Event Logger/ Fault Locator (including time synchronization equipment) shall be provided in the state transmission system for recording of dynamic performance of the system by the Users as stated in the Connection Agreement according to the agreed time schedule.

64. **Cyber Security,**

   All Users and STU shall have in place, a cyber security framework as specified in Information Technology Act, 2000, as amended from time to time, to identify the critical cyber assets and protect them so as to support reliable operation of the Grid.

65. **Schedule of Assets of the State Grid,**

   STU, other transmission licensees granted license by the Commission and the Generators shall maintain the schedule of their assets and host the same in their respective websites. The same shall be submitted to the Commission as and when called for.
66. **State Grid Connection Points/ Interface Points,**

(1) **State Generating Stations (SGS)**
   (i) Voltage may be 400/ 220/ 110/ 66/ 33 kV or as agreed with STU.
   (ii) Unless specifically agreed with STU, the Connection Point with generating station shall be the terminal isolator provided just before the outgoing gantry of the feeders/ evacuation lines.
   (iii) SGS shall operate and maintain all terminals, Communication and Protection equipment provided within the generating station.
   (iv) The provisions for the metering between generating station and STU system shall be as per the Metering Code.

(2) **Distribution Licensees,**
   (i) Voltage on LV side of power transformer may be 33 kV or 11 kV or as may be agreed with STU. For EHV consumers directly connected to transmission system, voltage may be 400kV/ 220 kV/ 110 kV/ 66kV.
   (ii) Unless specifically agreed with the Distribution Licensee, the Connection Point with STU shall be the terminal isolator provided just before the outgoing gantry of the feeder to Distribution Licensee or Individual EHV consumer as the case may be, from STU substation.
   (v) STU shall operate and maintain all terminals, Communication and Protection equipment provided within its substation. The provisions for the metering between STU and Distribution Licensees system shall be as per the Metering Code. Respective Users shall maintain their equipment beyond the outgoing gantry of feeders emanating from STU substation onwards.

(3) **Southern Regional Transmission System,**
    The Connection, protection scheme, metering scheme and the voltage shall be in accordance with the provisions of IEGC.

(4) **Independent Power Producers (IPPs), Captive Power Plants (CPPs), Extra High Voltage (EHV) Consumers and Open Access Consumers,**
   (i) Voltage may be 400kV/ 220kV/ 110kV/ 66 kV or as may be agreed with STU.
   (ii) When IPPs, CPPs, EHV Consumers or the Open Access Consumers own Substations, the Connection Point shall be the terminal isolator provided just before the gantry of outgoing/ incoming feeder in their premises.
CHAPTER III -- OPERATING CODE

Part IV - SYSTEM SECURITY ASPECTS

67. Introduction.-
   (1) All Users and STU shall endeavor to maintain efficient, secure and reliable grid operation of their respective power system and generating stations in synchronism with each other at all times, so that the whole State Transmission System operates as a synchronized system as well as integrated part of National Grid. STU shall endeavor to operate the interstate links so that interstate transfer of power can be achieved smoothly when required. Security of the power system and safety of the power equipments shall enjoy priority over economically optimal operations.
   (2) The system security relates to entire inter connected power system. The system security aspect therefore affects all Users of the regional interconnected power systems. The operation of the State Transmission System will be controlled and maintained by SLDC in accordance with directions and instructions of SRLDC under the provisions of IEGC.

68. Operating philosophy,-
   (1) All users connected with STS shall comply with this Operating Code and the directions issued by SLDC, to ensure integrated grid operation and for achieving maximum economy and efficiency in the operation of the power system.
   (2) A set of detailed operating procedures for the State Grid shall be developed and maintained by SLDC in consultation with the concerned persons for guidance of the staff of SLDC and the same shall be consistent with this State Grid Code and IEGC, to facilitate compliance with the requirement of the State Grid Code and IEGC.
   (3) The control rooms of the SLDC, Backup SLDC, Power plants, Substations of 110kV and above and any other control centers of all Transmission and Distribution Companies shall be manned round the clock; by qualified, adequately trained and certified personnel.

69. System Security Aspects,-
   (1) All switching operations, whether effected manually or automatic, will be based on policy guide lines of,-
      a) IEGC;
b) National Load Despatch Centre/ SRLDC/ SLDC/ Guidelines under the CEA Safety Regulations or any other Rules and Regulations framed under the Act;

c) State Grid Code;

d) KSERC’s directives;

e) State Grid Code Review Committee’s decisions.

(2) No part of the State Grid shall be deliberately isolated from the integrated Grid, except,-

a) Under an emergency, and conditions in which such isolation would prevent a total Grid collapse and/or enable early restoration of power supply;

b) For safety of human life;

c) When serious damage to a costly equipment is imminent and such isolation would prevent it;

d) When such isolation is specifically advised by SLDC;

e) On operation of under frequency/islanding scheme as approved by SRPC/ SGCRC/ SLDC.

All such isolations shall be as per the standing guidelines approved by SRPC/ SGCRC. Any other isolation shall be put up in the State Grid Code Review Committee for ratification. Complete synchronization of integrated Grid shall be restored, as soon as the conditions again permit it. The restoration process shall be supervised by SLDC, in co-ordination with SRLDC in accordance with approved operating procedures, formulated by SLDC/ SRLDC.

(3) No important element of the State grid shall be deliberately opened or removed from service at any time, without specific and prior clearance of SLDC, except in case of emergencies that may cause harm to the lives of the public or operating personnel. The list of such important grid elements on which the above stipulations apply shall be prepared by SLDC in consultation with the Users and STU, and be available at the websites of SLDC. In case of opening/ removal of any important element of the grid under an emergency situation, the same shall be communicated to SLDC at the earliest possible time after the event. Any emergency tripping not advised or permitted by SLDC shall be put up to the State Grid Code Review Committee for ratification in the next meeting.

(4) Any tripping, whether manual or automatic, of any of the elements mentioned above, shall be precisely intimated by the concerned User/ STU to SLDC. All grid elements shall be charged back into service only after obtaining clearance from SLDC. The details shall be communicated to the SLDC at the earliest, say within ten minutes of the event. The reason (to the extent determined) and the likely time of restoration shall also be intimated. All reasonable attempts shall be made for the element
restoration at the earliest. The information/data including that of the Disturbance Recorder, Event Logger outputs etc. containing the sequence of tripping and restoration shall be sent to SLDC for the purpose of analysis. Disturbance Recorder data may be directly made available at SLDC through suitable communication media for faster post fault analysis during grid disturbances.

(5) Maintenance of their respective power system elements shall be carried out by User/STU in accordance with the provisions in CEA Grid Standards. Any prolonged outage of power system elements of any User/STU, which is causing or likely to cause danger to the grid or sub-optimal operation of the grid, shall regularly be monitored by SLDC. SLDC shall report such outages to SGCRC, which shall finalize action plan and give instructions to restore such elements in a specified time period.

(6) All Coal/ Lignite based thermal generating units of 200 MW and above, Open Cycle Gas Turbine/ Combined Cycle Gas generating stations of capacity more than 50 MW and all Hydro units of 25 MW and above, which are synchronized with the grid, irrespective of their ownership, shall have their Governors in operation at all times in accordance with the following provisions,-

i) Coal/ Lignite based thermal generating units of >=200 MW having Electro Hydraulic Governor (EHG) System, Gas Turbine units of >50 MW and Hydro (except those with upto three hours pondage) generating units of 25 MW and above shall be operated under Restricted Governor Mode of Operation (RGMO).

ii) The Restricted Governor Mode of Operation shall have essentially the following features,-

a) There should not be any reduction in generation in case of improvement in grid frequency below 50 Hz. (for example if grid frequency changes from 49.9 to 49.95 Hz. Then there shall not be any reduction in generation). Whereas for any fall in grid frequency, generation from the unit should increase by 5%, limited to 105 % of the MCR of the unit subject to machine capability.

b) Ripple filter of +/- 0.03 Hz shall be provided so that small changes in frequency are ignored for load correction, in order to prevent Governor hunting.

c) If any of these generating units are required to be operated without its Governor in operation as specified above, the SLDC shall be immediately informed about the reason and duration of such operation. All Governors shall have a droop setting of between 3% and 6%.
d) After stabilization of frequency around 50 Hz, the Commission may review the above provision regarding the Restricted Governor mode of operation and Free Governor Mode of Operation (FGMO) may be introduced.

(iii) All other generating units including those with pondage upto 3 hours, Wind and Solar generators and Nuclear Power Stations shall be exempted from Regulations 69 (6), (7) and (8), till the Commission reviews the situation:
Provided that if a generating unit cannot be operated under Restricted Governor mode operation, it shall be operated in Free Governor mode operation with Manual intervention to operate in the manner required under Restricted Governor mode operation.

(7) Facilities available with/ in Load Limiters, Automatic Turbine Run-up System (ATRS), Turbine Supervisory Coordinated Control system etc. shall not be used to suppress the normal Governor action in any manner and no dead bands and/ or time delays shall be deliberately introduced except as specified in Regulation 69(6):
Provided that periodic checkup by third party should be conducted at regular intervals of not more than two years, through independent agencies selected by SLDC. The cost of such tests shall be recovered by SLDC from the Generators. If deemed necessary by SLDC, the test may be conducted more than once in two years.

(8) All Coal and Lignite based thermal generating units of 200 MW and above, Open cycle Gas Turbine/ Combined Cycle Gas Generating stations of capacity more than 50 MW and all Hydro units of 25 MW and above operating at or upto 100% of their Maximum Continuous Rating (MCR) shall have capability of (and shall not in any way be prevented from) instantaneously picking upto 105%, 105% and 110% of their MCR respectively, when frequency falls suddenly. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit, not complying with the above requirements, shall be kept in operation (synchronized with the State grid) only after obtaining the permission of SLDC. The SLDC can also direct a generator to come to its Technical Minimum in line with CEA/ KSERC notifications issued from time to time, depending on the grid situation.

(9) For the purpose of ensuring primary response, SLDC shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall
ensure that there is margin available for providing Governor Action as primary response. In case of gas/liquid fuel based units, suitable adjustment in Installed Capacity should be made by SLDC for scheduling, in due consideration of prevailing ambient conditions of temperature and pressure vis-a-vis; site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:
Provided that scheduling of Hydro stations shall not be reduced during high inflow period in order to avoid spillage:
Provided further that the VWO margin shall not be used by SLDC to schedule Ancillary Services.

(10) The recommended rate for changing the Governor setting, i.e., supplementary control for increasing or decreasing the output (generation level) for all generating units, irrespective of their type and size, would be one (1.0) per cent per minute or as per manufacturer’s limits.

(11) Except under an emergency, or to prevent an imminent damage to costly equipment or danger to human/animal life, no User shall suddenly reduce his generating unit output by more than 100 MW without prior intimation to and consent of the SLDC. Similarly, no User shall cause a sudden variation in its load by more than 100 MW without prior intimation to and consent of the SLDC, particularly when frequency is deteriorating.
All users shall ensure that temporary over voltage due to sudden load rejection and the maximum permissible values of Voltage unbalance shall remain within limits specified under CEA Grid Standards as amended from time to time.

(12) All Generating Units shall normally have their Automatic Voltage Regulators (AVRs) in operation. If a Generating Unit of over 50 MW capacity is required to be operated without its AVR in service, SLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be got properly tuned by the respective generating unit owner as per a plan prepared for the purpose by the STU from time to time. STU will be allowed to carry out checking the functioning of PSS and AVR and further tuning it, wherever considered necessary.

(13) SGS and other generating stations connected to the Grid shall follow the instructions of SLDC for backing down/boxing up (ramping-down) and shutting down the generating unit(s). SLDC shall provide the certificate for the period of the backing down/boxing up or shutting down for the purpose of computing the deemed generation, if required.

(14) Provision of protections and relay settings in the State Transmission System shall be coordinated by the State Protection Co-ordination Committee as per the plan to be finalized by the Committee. The Committee shall also prepare islanding schemes and ensure its
implementation in accordance with CEA Grid Standards. All users shall ensure that installation and operation of protection system shall comply with the provisions of CEA Grid Standards.

(15) Various steps shall be taken for Frequency Management and Voltage Management as per these Regulations, so as to ensure system security.

(16) All Users shall take all possible measures to ensure that the grid frequency always remains within the 49.9 – 50.5 Hz band or as specified by the Commission.

(17) All generation units with capacity of 200 MW and above and all substations of 220 kV and above shall be provided with the facilities of Disturbance Recorders (DRs) and Event Loggers (ELs) with GPS time synchronization. Such Disturbance Recorders (DRs) and Event Loggers (ELs) may be either independent stand alone type or provided with the Numeric relays in service at these substations.

(18) Distribution licensees/ STU shall provide Automatic under frequency and df/dt relays for,-

(i) load shedding in their respective systems, to arrest frequency decline that could result in a collapse/ disintegration of the grid, as per the plan finalized by the SLDC and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency; and

(ii) to effect Islanding.

(iii) All distribution licensees/ STU shall ensure that the above under frequency and df/dt relays for load shedding/ islanding schemes are always functional. The provisions regarding under frequency and df/dt relays of relevant CEA Regulations shall be complied with. SLDC shall carry out periodic inspection of the under frequency and df/dt relays and maintain proper records of the inspection. SLDC shall decide and intimate the action required by the distribution licensees and STU to get required load relief from under frequency and df/dt relays. All distribution licensees and STU shall abide by these decisions. SLDC shall keep a comparative record of expected load relief and actual load relief obtained in Real time system operation.

(19) All Users, STU/ SLDC shall also facilitate identification, installation and commissioning of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system, to operate the transmission system closer to their limits and to protect against situations such as voltage collapse and cascade tripping, tripping of important corridors etc. Such schemes would be finalized by SLDC in consultation with SOCC and SPCC and shall always be kept in service. If any SPS is to be taken out of
service, permission of SLDC shall be obtained indicating reason and duration of anticipated outage from service.

(20) Procedures shall be developed and documented to recover from partial/total collapse of the grid in accordance with CEA Grid Standards and to periodically update the same in accordance with the requirements given under Regulation 83. These procedures shall be followed by all the Users, STU and SLDC to ensure consistent, reliable and quick restoration.

(21) Each User, STU, SLDC shall provide and maintain adequate and reliable communication facility internally and with other Users/STU/SLDC to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes, e.g., Users to Distribution Licensees/respective entity to SLDC.

(22) All the Users and STU shall send information/data including disturbance recorder/sequential event recorder output to SLDC within 24 hours for purpose of analysis of any grid disturbance/event. No User, STU shall block any data/information required by the SLDC and SRPC for maintaining reliability and security of the grid and for analysis of an event.

(23) All Users, SLDC and STU shall take all possible measures to ensure that the grid voltages always remain within the operating range specified in Regulation 47(6) above.

(24) All Users and STU shall provide adequate voltage control measures as finalized by SLDC, to prevent voltage collapse and shall ensure its effective application to prevent voltage collapse/cascade tripping. Voltage fluctuation limits and voltage waveform quality shall be maintained as specified in CEA Grid Standards.

70. Special requirements for Solar/Wind/RE Generators,-

(1) System operator (SLDC) shall make all efforts to evacuate the power from Solar, Small hydel, Cogeneration, Wind and other Renewable Energy Sources and treat them as must run station. System operator may instruct the Solar/Wind/RE generator to back down generation on consideration of grid security or safety of any equipment or personnel is endangered and Solar/Wind/RE generator shall comply with the same. For this, Voice, Text and Real time Data Acquisition System facility shall be provided for transfer of information to SLDC.

(2) SLDC may direct a Wind farm to curtail its Volt Ampere Reactive lagging (VAR) drawal/injection in case the security of grid or safety of any equipment or personnel is endangered.

(3) During the Wind generator start up, the Wind generator shall ensure that the Reactive power drawal (inrush currents in case of induction generators) shall not affect the grid performance.
Part V
OPERATIONAL PLANNING

71. Introduction.-

(1) This part describes the process by which SLDC carries out the operational planning and demand control procedures to permit reduction in Demand for any reason.

(2) This is required to enable SLDC to achieve a reduction in demand to avoid Operating problems on all or parts of the State Transmission System. SLDC will utilize demand estimation and Demand Control in a manner which does not unduly discriminate against any one or group of customers.

72. Demand Estimation,-

(1) The demand estimation is to be done on daily/ weekly/ monthly/ yearly basis for current year for load - generation balance planning. It shall be the responsibility of all distribution licensees/ users and other concerned persons to provide relevant data and other information as required by SLDC for demand estimation. The SLDC shall carry out system studies for operational planning purposes using this demand estimate.

(2) The long term demand estimation/ load forecast (for more than 1 year) shall be done by the planning department of STU in accordance with the provisions of Part II. SLDC shall be provided with a copy of the same as and when it is finalized. Demand Estimation for period upto one year ahead shall be done by SLDC.

(3) Attention shall also be paid by SLDC in demand forecasting for special days such as important festivals, religious occasions and National Holidays having different crests and troughs in the daily load-curve as compared to normal weather conditions and days.

(4) SLDC shall furnish data and participate in deliberations on data for load generation balance or annual demand, availability and shunt capacitor requirement studies of SRPC.

(5) The SLDC shall develop methodologies/ mechanisms for daily/ weekly/ monthly/ yearly demand estimation (MW, MVAR and MWh) for operational purposes, which would be used in the day ahead scheduling. Based on this demand estimate and the estimated availability from different sources, SLDC shall plan demand management measures like load shedding, power cuts etc. and shall ensure that the same is implemented by the distribution licensees/ users. All distribution licensees/ users shall abide by the demand management measures of the SLDC and shall also maintain historical database for demand estimation.

(6) SLDC shall carry out its own demand estimation from the historical Data and weather forecast data from time to time. All distribution licensees/ users and other concerned persons shall provide relevant data and other information as required by SLDC for demand estimate. All distribution licensees/ users shall provide to SLDC their estimates of demand for the
year ahead, month wise, at each inter connection point for the next financial year by 1\textsuperscript{st} October of each year. All distribution licensees/users shall also provide daily demand for the month ahead at each inter connection point, by 25\textsuperscript{th} of current month, for the forthcoming month.

(7) All distribution licensees/users shall provide to SLDC on day ahead basis at 9.00 AM each day, their estimated demand for each 15 minute time block for the ensuing day along with the estimates of load that may be shed when required, in discrete blocks with the details of arrangements of such load shedding.

(8) While the demand estimation for operational purposes is to be done on a daily/weekly/monthly basis initially, mechanisms and facilities at SLDC shall be created at the earliest but not later than three months from the commencement of this State Grid Code to facilitate on line estimation of demand for daily operational use for each 15 minutes block.

(9) The SLDC shall take into account the Wind Energy/Solar Energy forecasting to meet the active and reactive power requirement. Date of introduction of wind energy forecasting, and its permissible errors will be notified separately by the Commission.

(10) In order to facilitate intra state open access, Total Transfer Capability (TTC)/Available Transfer Capability (ATC) of the state grid transmission line wise, on three month ahead basis, shall be fixed by SLDC. All distribution licensees/users shall furnish estimated demand and availability data to SLDC for this estimation.

73. Demand Management,-

(1) This Regulation is concerned with the provisions to be made by SLDC to effect a reduction of demand in the event of insufficient generating capacity, and inadequate transfers from external interconnections to meet demand, or in the event of breakdown or congestion in intra-state or inter-state transmission system or other operating problems (such as frequency, voltage levels beyond normal operating limit, or thermal overloads etc.) or overdrawal of power vis-à-vis that of the regional entities beyond the limits mentioned in DSM Regulations of CERC/KSERC, for maintaining grid security.

(2) Procedure,-

(i) Primarily the need for demand control would arise on account of the following conditions:-

a) Variations in demand from the estimated or forecasted values, which cannot be absorbed by the grid;

b) Unforeseen generation/transmission outages resulting in reduced power availability; and

c) Heavy reactive power demand causing low voltages.

(ii) SLDC shall match the consolidated demands of the Distribution Licensees with consolidated generation availability from SGS, ISGS, IPP, CPP and other sources and exercise the Demand Control to ensure that there is a balance between the energy availability and the Distribution Licensees’ demand plus losses plus the required reserve.
(iii) SLDC would maintain a historical database for the purpose of Demand Estimation and shall be equipped with the state-of-the-art tools such as Energy Management System (EMS) for short-term demand estimation to plan in advance as to how the load would be met without overdrawing from the grid.

(3) Demand Disconnection,-

(i) SLDC/ distribution licensee/ users and EHV consumers connected to STS shall initiate action to restrict the drawal of its control area, from the grid, within the net drawal schedule.

(ii) The SLDC/ distribution licensee/ users and EHV consumer shall ensure that requisite load shedding is carried out in its control area so that there is no over drawal.

(iii) Each Distribution licensee/ User/ STU shall formulate contingency procedures and make arrangements that will enable demand disconnection to take place, as instructed by the SLDC, under normal and/or contingent conditions. These contingency procedures and arrangements shall be regularly updated by distribution licensee/ User/ STU and monitored by SLDC. SLDC may direct any User/ STU to modify the above procedures/ arrangement, if required, in the interest of grid security and the concerned User/ STU shall abide by these directions.

(iv) The SLDC through respective Distribution Licensees/ Users shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like under frequency relays, rotational load shedding, demand response (which may include lower tariff for interruptible loads) etc. within three months from the commencement of this State Grid Code, to reduce overdrawal in order to comply with clauses (i) and (ii) above. These schemes shall be duly approved by the functional committee i.e. Operation and Co-ordination Committee formed by State Grid Code Review Committee.

(v) The particulars of feeders or group of feeders at a STU substation which shall be tripped under under-frequency load shedding scheme whether manually or automatically on rotational basis or otherwise shall be displayed on the website of SLDC/ STU and will also be available at the substation for information of the Consumer(s).

(vi) In order to maintain the frequency within the stipulated band and maintaining the network security, the interruptible loads shall be arranged in four groups of loads, for scheduled power cuts/load shedding, loads for unscheduled load shedding, loads to be shed through under frequency relays/ df/dt relays and loads to be shed under any System Protection Scheme. These loads shall be grouped in such a manner, that there is no overlapping between different Groups of loads. In case of certain contingencies and/ or threat to system security, the SLDC may direct any distribution licensee/ user or EHV consumer connected to the STS to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon. Distribution licensee/ User or EHV consumer shall send compliance report immediately after compliance of these directions to SLDC.
(vii) SLDC may direct any distribution licensee/ user/ EHV consumer connected to the STU to curtail drawal from grid. SLDC shall monitor the action taken by the concerned entity and ensure the reduction of drawal from the grid as directed.

(viii) SLDC shall devise standard, instantaneous, message formats in order to give directions in case of contingencies and/or threat to the system security to reduce deviation from schedule by any user/ distribution licensee/ EHV consumer at different overdrawal under drawal/ over injection/ under injection conditions depending upon the severity of the overdrawal. The concerned user/ distribution licensee/ EHV consumer shall ensure immediate compliance with these directions of SLDC and send a compliance report to the SLDC.

(ix) All distribution licensees, other Users or EHV consumers shall comply with directions of SLDC and carry out requisite load shedding or backing down of generation in case of congestion in transmission system to ensure safety and reliability of the system. The procedure for application of measures to relieve congestion in real time as well as provisions of withdrawal of congestion shall be in accordance with Central Electricity Regulatory Commission (Measures to relieve congestion in real time operation) Regulations, 2009.

(x) The measures taken by the distribution licensee/ user or EHV consumer shall not be withdrawn as long as the frequency remains at a level lower than the limits specified in Regulation 68 or the congestion continues, unless specifically permitted by the SLDC.

(xi) Demand control can also be exercised by SLDC through direct circuit breaker tripping effected from SLDC using RTUs and under frequency detection by SCADA or through telephonic instructions. No demand shed by operation of under frequency relays shall be restored without specific directions from SLDC.

74. **Load Crash,-**

(1) In the event of load crash in the system due to weather disturbance or any other reasons, the situation would be controlled by SLDC by getting the following methods implemented from distribution licensee(s) and other concerned Users in descending priorities:-

   (i) Lifting of the load restrictions, if any;
   (ii) Exporting the power to neighbouring regions/ states;
   (iii) Backing down of thermal stations with a time lag of 5-10 minutes for short period in merit order;
   (iv) Closing down of hydel units (subject to non spilling of water and effect on irrigation) keeping in view the inflow of water into canals and safety of canals/ hydel channels.

(2) Any other instruction issued by SLDC shall assume priority over all the above methods. The above methodology shall be reviewed from time to time in the State Operation and Co-ordination Committee.

(3) While implementing the above, the system security aspects as per provisions in Section 5.2 of IEGC and Part IV of the State Grid Code should not be violated. Further, in case of hydro generation linked with irrigation requirements, the actual backing down or closing down of such
hydro units shall be subject to limitations on such account and to avoid spillage of water.

75. **Demand Control by Distribution Licensee/ Users,-**
Distribution Licensees and other Users shall provide SCADA and data management systems in their area of control for efficient working of Distribution Systems. The Distribution Licensees/ Users shall prepare and send SCADA and data management system report to SLDC. Distribution Licensees/ Users shall provide substation automation equipment within one year from the date of coming into effect of the State Grid Code at important substations identified by SLDC in consultation with Distribution Licensee(s).

76. **Operational Liaison,-**
(1) This Grid Code sets out the requirements for the exchange of information in relation to Operations and/or Events on the total grid system which have or will have an effect on the ISTS/ STS/ User System.

(2) The Operational liaison function is a mandatory built-in hierarchical function of the SLDC, STU, Distribution Licensees and Users, to facilitate quick transfer of information to operational staff. It will correlate the required inputs for optimization of decision making and actions.

(3) Operations and events on a User/ STU system,-
   a) Before any operation is carried out by a User, STU or transmission licensee shall obtain permission of the SLDC, and give details of the operation to be carried out. In case such operation is likely to have impact on other regions, the RLDC of those Regions shall also be informed.

   b) All planned outages for the next month shall be communicated to SLDC by 20th of the current month so as to enable SLDC to study the impact and communicate to SRPC before 25th of the current month for outage coordination approval.

   c) Immediately following an event, the User, STU, transmission licensee or Distribution Licensee shall inform SLDC about the event.

   d) All operational instructions given by SLDC shall have unique codes which shall be recorded and maintained as specified in the Central Electricity Authority (Grid Standards) Regulations, 2010.
77. **Introduction**

(1) This part describes the process by which STU shall carry out the planning of outage in the State Transmission System, in a coordinated and optimal manner keeping in view the State or Regional system operating conditions and the balance of generation and demand.

(2) The generation output and transmission system should be adequate after taking into account the outages to achieve the security standards.

(3) Annual outage plan shall be prepared in advance for the financial year by the SLDC based on the outage plan provided by STU/distribution licensees/Users and will be reviewed during the year on quarterly and monthly basis. All Users, STU etc. shall follow these annual outage plans. If any deviation is required the same shall be with prior permission of SLDC. The outage planning of run-of-the-river hydro plant, wind and solar power plant and its associated evacuation network shall be planned to extract maximum power from these renewable sources of energy. Outage of wind generator should be planned during lean wind season, outage of solar, if required during the rainy season and outage of run-of-the-river hydro power plant in the lean water season.

(4) The objective of this part are,

a) To produce a coordinated generation and transmission outage programme for the State grid, considering all the available resources and taking into account transmission constraints, as well as, irrigation requirements.

b) To minimize surplus or deficits, if any, in the system requirement of power and energy and help operate system within Security Standards.

c) To optimize the transmission outages of the elements of the State grid without adversely affecting the grid operation but taking into account the Generation Outage Schedule, outages of User/STU systems and maintaining system security standards.

78. **Outage Planning Process**

(1) Each User and STU shall provide their proposed outage programme in writing for ensuing financial year to SLDC for preparing an overall outage plan for the State Transmission System as a whole. SLDC shall be responsible for analyzing the outage schedules of all users including SGS, Distribution Licensees, Transmission Licensee(s) and STU’s schedules, for outage of Transmission network and preparing a draft annual Outage Plan for the State Transmission System, in coordination with the Outage Plan prepared for the region by SRPC. The Users shall furnish the information to SLDC as per Appendix C.

(2) However, SLDC is authorized to defer the outage in case of any of the following events:-

a) Major grid disturbance;
b) System Isolation;
c) Partial/ complete black out in the State;
d) Any other event in the system that may have an adverse impact on system security by the proposed outage.

(3) Each User, STU and other generating station shall obtain approval of SLDC, prior to availing the Outage.

(4) SLDC while releasing any circuit for outage shall issue specific code to authorized person. Such circuit shall be connected back to the State Transmission System after specific code is returned by the authorized person to whom it is issued and thereafter with the approval by SLDC.

(5) This restriction shall not be applicable to individual Generating Unit(s) of a CPP.

79. Annual Outage Planning.-

(1) Scheduled outage of power stations of capacity 10 MW and above or as notified by SLDC from time to time, will be subject to annual planning.

(2) Provided that scheduled outage of power stations of 50 MW and above and EHV lines as notified by SRLDC, will also be subject to annual planning by SRLDC in co-ordination with SLDC.

(3) SGS (except CPPs) connected to the State Grid shall furnish their proposed Outage programme for the next financial year in writing by 1st October each year. SGS Outage programme shall contain details like identification of unit, reason for outage, generation availability affected due to such outage, outage start date and duration of outage.

(4) SLDC shall also obtain from STU and other transmission licensee(s), the proposed outage programme for Transmission lines, equipments, substations etc. for next financial year by 1st October each year. STU outage programme shall contain identification of lines/ substations, reasons for outage, outage start date and duration of outage.

(5) SLDC shall prepare and submit Load Generation Balance Report (LGBR) for peak as well as off peak scenario and annual outage plan, by 31st October for the next financial year to SRPC. The annual plans for managing the deficit/ surplus shall be clearly indicated in the LGBR.

(6) Scheduled outage of power stations and EHV transmission lines affecting regional power system shall be effected only with the approval of SRLDC in co-ordination with SLDC.

(7) SLDC shall then come out with a draft LGBR for peak as well as off peak scenario and also prepare draft annual outage plan for the next financial year in consultation with SRPC by 30th November of each year for the State Grid, taking into account the available resources in an optimal manner and to maintain security standards. This will be done after carrying out necessary system studies and, if necessary, the outage programmes shall be rescheduled and LGBR shall be modified. Adequate balance between generation and load requirement shall be ensured while finalizing outage programmes. The draft LGBR and draft outage plan shall be uploaded by SLDC on its website.

(8) The outage plan shall be finalized in consultation with SRLDC/ SRPC. The LGBR after considering the comments/ observations of stakeholders shall
be finalised by SLDC in consultation with SRPC/ SRLDC by 31st Dec. The final outage plan and final LGBR shall be uploaded on the website of SLDC and shall also be intimated to all Users, STU, SGS and other licensees by 15th January. In case of emergency in the system, viz., loss of generation, break down of transmission line affecting the system, grid disturbances, system isolation etc., SLDC may conduct studies again before clearance of the planned outage.

(9) The detailed generation and transmission outage programmes shall be based on the latest annual outage plan (with all adjustments made to date).

(10) The above annual outage plan shall be reviewed by SLDC on quarterly and monthly basis in coordination with all parties concerned, and adjustments made wherever found to be necessary.

(11) SLDC shall submit half yearly reports to the Commission indicating deviation in outages from the plan along with reasons. These reports shall also be put up on the SLDC website.

(12) Scheduled outage of power stations of capacity 10 MW and above, of all EHV lines and HV lines forming interconnection between two EHV substations (and those notified as such by SLDC) shall be approved by SLDC, 24 hours in advance based on prevalent operating conditions. Approval shall be sought 72 hours before the scheduled outage by the power stations of capacity 25 MW and above or 110 kV and higher voltage transmission lines (other than radial lines). For other power stations and lines such approval shall be sought 48 hours in advance.

(13) In respect of scheduled outage referred in this section a calendar shall be formulated in respect of annual outage planning for the ensuing financial year. Such outage plan shall be deliberated and finalised in the meeting of the State Operation and Co-ordination Committee (SOCC).

(14) Outage plans for EHV lines/ substations of more than 60 MVA transformation capacities shall be intimated to SLDC by the respective utilities.

80. **Availing of Planned Shutdown,-**

(1) SLDC would review on daily basis the outage schedule for the next two days and in case of any contingency or adverse conditions, defer any planned outage as deemed fit clearly stating the reasons thereof. The revised dates in such cases would be finalized in consultation with the User.

(2) The shutdown for scheduled outage shall be taken in accordance with the provisions of Part VIII of this State Grid Code, to ensure inter user coordination.
81. **Introduction**

1. This part describes the steps in the recovery process to be followed by all Users in the event of total or partial blackout of the State Transmission System or Regional Transmission System or National Grid System.

2. The objective of this part is to define the responsibilities of all Users to achieve the fastest recovery of the grid in the event of State Transmission System or Regional System or National Grid System blackout, taking into account the essential loads to be restored, generator/station capabilities and system constraints for transfer of power from neighbouring systems/generating stations.

3. The main objectives are to achieve the following:
   a. Restoration of the total system and associated demand in the shortest possible time;
   b. Resynchronization of parts of the system which have ceased to be in synchronism;
   c. To ensure that the communication arrangements for use in circumstances of serious disruption to the system are available, to enable senior management representatives of the SLDC to interact with officials of STU, Transmission Licensee and the users who are authorized to take decisions on behalf of the Transmission Licensee or the user;
   d. To ensure that the Transmission System can operate in the event, the SLDC is incapacitated for any reason.

82. **Contingency Planning Procedure**

1. SLDC shall be prepared to face and efficiently handle the following types of contingencies and restoration of system back to normal in accordance with the System Restoration Procedure of Southern Region prescribed under IEGC and further supplemented by SLDC for Kerala State Grid in consultation with STU/SGS/transmission and distribution licensees and other Users:
   a) Partial system black out in the state due to multiple tripping of the transmission lines emanating from power stations/substations;
   b) Total black out in the state/region;
   c) Synchronization of system islands and system split.

2. In case of partial black out in the system/state/region/national grid, priority is to be given for early restoration of power station units, which have tripped. Start up power for the power station shall be extended through shortest possible route and within shortest possible time from adjoining substation/power station where the supply is available. Synchronizing facility at all power stations and 220 kV and above substations having inter-connection with ISTS shall be available.
(3) In case of total regional black out, SLDC in-charge shall follow the system restoration procedure and for that purpose coordinate and follow the instructions of SRLDC for early restoration of the entire grid. Black start power stations shall be immediately started. Start up power to the thermal stations shall be given by the hydel stations or through interstate supply, if available. All possible efforts shall be made to extend the hydel supply to the thermal power stations through shortest transmission network so as to avoid high voltage problem due to low load conditions. For safe and fast restoration of supply, SLDC shall formulate the proper sequence of operation for major generating units, lines, transformers and load within the state in consultation with SRLDC. The sequence of operation shall include opening, closing/ tripping of circuit breakers, isolators, on load tap changers etc.

83. **Restoration/ Recovery Procedure,**

(1) Kerala falls under the Southern Regional Grid. SLDC shall follow the sequence prescribed for restoration procedure, utilize black start facility/ avail start up power and synchronize the system elements as per the directions and instructions prescribed for Southern Regional System in the latest SR Restoration Procedure. Detailed procedure for restoration of the State Transmission System shall be prepared by SLDC for the following contingencies and shall be in conformity with the System Restoration Procedure of the Southern Region prescribed under IEGC:-

a) Total System Black out;
b) Partial System Blackout;
c) Synchronization of System Islands and System Split.

(2) The restoration process shall take into account the generator capabilities and the operational constraints of Regional and the State Transmission System with the objective of achieving normalcy in the shortest possible time. All Users should be aware of the steps to be taken during major Grid Disturbance and system restoration process.

(3) Detailed plans and procedures for restoration of the State grid under partial/ total blackout shall be developed by SLDC in consultation with all Users, STU and SRLDC and shall be reviewed/ updated annually.

(4) Detailed plans and procedures for restoration after partial/ total blackout of each User’s or STU system within the State will be finalized by the concerned User’s or STU in coordination with the SLDC. The procedure will be reviewed, confirmed and/ or revised once every subsequent year. Mock trial runs of the procedure for different subsystems shall be carried out by the Users or STU at least once in every six months under intimation to the SLDC.

(5) The SLDC is authorized during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.
(6) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

(7) The Generating Companies shall be responsible for commencing their Black start procedure on the instruction of SLDC and steadily increasing their generation, according to the demand intimated by SLDC.

84. Special Considerations,

(1) During restoration process following the State Transmission System or Regional System or National Grid System blackout conditions, normal standards of voltage and frequency shall not apply.

(2) Distribution Licensees/ Users with essential loads shall separately identify non-essential components of such loads, which may be kept off during system contingencies. Distribution Licensees shall draw up an appropriate schedule with corresponding load blocks in each case and assign relative priority in restoration of essential loads. The non-essential loads can be put on only when system normalcy is restored, as advised by SLDC.

(3) All Users shall pay special attention to carry out the procedures so that secondary collapse due to undue haste or inappropriate loading is avoided.

(4) Despite the urgency of the situation, careful, prompt and complete logging of all operations and operational messages shall be ensured by all Users to facilitate subsequent investigation into the incident and the efficiency of the restoration process. Such investigation shall be conducted promptly after the incident.

85. Warnings,

(1) An oral warning shall be issued by SLDC and confirmed in writing as well, to the STU/ Transmission licensee and the users, who may be affected when SLDC knows that there is a risk of widespread and serious disturbance to the whole, or part of the total system.

(2) If sufficient time is available, the warning shall contain such information as the SLDC considers reasonable, to explain the nature, extent of the anticipated disturbance etc. to the user/ Transmission licensee, provided that such information is available to SLDC.

(3) Each user and STU/ Transmission licensee, on receipt of such a warning, shall take necessary steps to warn the operational staff and maintain their plant and apparatus in the condition in which it is best able to withstand the anticipated disturbance for the duration of the warning.

(4) Scheduling and dispatch may be affected during the period covered by such a warning.

86. Loss of Communication with SLDC,

(1) In the event of loss of communication with SLDC, the provision made as above shall not apply; instead, the following provision shall apply:
(2) Each Generating station shall continue to operate in accordance with the last dispatch instruction issued by SLDC, but shall use all reasonable endeavors to maintain the system frequency at the target of 50 hz, +/- 0.05 hz by monitoring frequency, until such time the new dispatch instructions are received from SLDC.

87. Post Disturbance Analysis,-

(1) SLDC, as per guidelines and instructions from SRLDC, shall carryout the post disturbance analysis of all major grid disturbances resulting into total or partial system blackout and system split and de-synchronism of any part of the State Grid. All users shall co-ordinate and furnish the data pertaining to the system disturbance to enable SLDC to analyze the system disturbance and furnish report to SRLDC in accordance with Section 5.9 of the IEGC.

(2) State Protection Coordination Committee shall also review the data collected and analyze the failure of protection system either of STU or any User and recommend modification and/ or improvement in the protection system/ relay setting schemes and, if necessary, of the islanding and restoration scheme of Southern Region, to be carried out by the Grid Users.
Part VIII
INTER USER BOUNDARY SAFETY

88. Introduction,
(1) This part sets down the requirements for maintaining safe working practices for operation and maintenance of system elements associated with inter user boundary operations. It lays down the procedure to be followed when work is to be carried out on electrical equipments that are connected to another User's system/ state grid.

(2) The objective of this part is to achieve agreement and consistency on the principles, procedures and practices in electrical work on safety, as prescribed in the CEA Safety Regulations 2010 and Part 1, Section 19, ‘Safety in Electrical work’ of National Electrical Code (SP 30: 2011), as amended from time to time, when working across the inter user boundary between one User and another User.

89. Designated Officers/ Control Persons,
STU and all Users shall nominate authorized persons to be responsible for the coordination of safety across each inter user boundary. These persons shall be referred to as Designated Officer(s) or Control Person.

90. Procedure,
(1) STU shall issue a list of Designated Officers (names, designation and telephone numbers) to all Users who have a direct inter user boundary with STU or other Users. This list shall be updated promptly whenever there is change of name, designation or telephone number.

(2) All Users with a direct inter user boundary with STU or other User system shall issue a similar list of their Designated Officers to STU or other User(s), which shall be updated promptly whenever there is a change.

(3) Whenever work across an inter-user boundary is to be carried, the Designated Officer of the User including STU itself, wishing to carry out work shall personally contact the other Designated Officer and collect the Permit to Work (PTW) with code word. PTW will also be returned personally by designated Officer using same code word. If the PTW cannot be obtained/ returned personally, the Designated Officers shall contact through telephone and exchange Code words and have cross checks to ensure correct identification of both agencies before issuing/ returning PTW.

(4) If the works extend over more than one shift, the Designated Officer shall ensure that the relief Designated Officer is fully briefed on the nature of the work and the code words in operation.

(5) The Designated Officer(s) shall co-operate to establish and maintain the precautions necessary for the required work to be carried out in a safe manner. Both the established isolation and the established earth shall be locked in position, where such facilities exist, and shall be clearly identified and entered into the log sheet.

(6) Work shall not commence until the Designated Officer of the User including STU itself, wishing to carry out the work, is satisfied that all the safety precautions have been established. This Designated Officer shall issue agreed safety documentation Permit To Work (PTW)/ Line Clear Permit (LCP) to the working party to allow work to commence. The PTW in respect
of specified EHV lines and other interconnections shall be issued with the consent of SLDC.

(7) When work is completed and safety precautions are no longer required, the Designated Officer who has been responsible for the work being carried out shall make direct contact with the other Designated Officer to return the PTW and removal of those safety precautions. Return of Permit to Work (PWR) in respect of specified EHV lines and interconnections shall be informed to SLDC.

(8) The equipment shall only be considered as suitable for connecting back to service when all safety precautions are confirmed as removed, by direct communication using code word contact between the two Designated Officers, and after ensuring that the return of agreed safety documentation (PWR) from the working party has taken place.

(9) STU shall develop an agreed written procedure for inter user boundary safety and regularly update it.

(10) Any dispute concerning inter user Boundary Safety shall be resolved at the level of Operation and Co-ordination Committee.

91. Special Considerations,-

(1) For inter user boundary between STU and other User’s circuits, all Users shall comply with the agreed safety rules, which must be in accordance with CEA Safety Regulations or any other rules and regulations framed under the Act.

(2) Each Designated Officer shall maintain a legibly written safety log, in chronological order, of all operations and messages relating to safety coordination sent and received by him. All safety logs shall be retained for a period of not less than 10 years.

(3) All the equipments on cross Boundary Circuits which may be used for the purpose of safety coordination and establishment of isolation and earthing shall be permanently and clearly marked with an identification number or name, being unique to the particular substation. The equipment shall be regularly inspected and maintained in accordance with the manufacture’s specifications.

(4) Each of the Distribution licensees connected to the transmission system shall maintain an updated map of distribution system pertaining to the area fed by each substation and exhibit the same in respective substation. The same shall be uploaded in their websites.

92. Safety Standards and Permit to Work,-

(1) The Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010, formulates the precautions to be taken for ensuring safety to the general public, consumers of electricity and the workmen. This forms an integral part of the State Grid Code and STU/Transmission Licensee and all the users shall comply with this standard.

(2) STU/Transmission Licensee shall prepare his own safety manual for the Transmission Lines and substations based on this code and safety standards. For the guidance of the shift operators, Operation and Maintenance Manuals for each substation shall be prepared by the
Licensee. These manuals shall contain all the maintenance and operation schedules, based on the recommendations of the manufacturer of the various equipments installed in the substation. These manuals shall be periodically reviewed based on the experience gained and on replacement of the equipments. A maintenance register for the equipments, including the station batteries shall be maintained at the respective substations. These shall be updated as and when the maintenance work is carried out and shall be periodically reviewed by the appropriate higher authority in whose control the substation falls. Similar registers shall be maintained for the Transmission Lines.

(3) The Operation Manual shall clearly contain the details of isolation and earthing to be provided for allowing work on the equipment. The Single Line Diagram (SLD) of the substation indicating the positions of various isolating devices shall be prominently displayed in the station. Charts showing the clearances from live parts (section clearance) for working on the isolated equipment where workmen are allowed to work shall be displayed prominently at each substation.

(4) The danger boards as stipulated in the Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2010 and in relevant Indian Standards shall be displayed at the places approachable by the general public.

(5) Regular maintenance shall be carried out on all the Transmission Lines in accordance with IS: 5613 and relevant standards and records of all these shall be maintained. Wherever possible, hot line checking and replacement of failed insulators shall be made before and after every monsoon.

(6) All the equipments in the receiving stations and substations shall be maintained in good condition as per the manufacturer’s manuals and relevant Indian/ International Standards wherever available. The relays and circuit breakers shall be checked for their proper operations whenever these are taken out for maintenance purposes. The station batteries shall be maintained in good working condition by carrying out routine checks and maintenance works. The DC system provided in all the stations shall be properly maintained with no appreciable leakage current. An online monitoring system for monitoring of leakage and detection of ground faults shall be provided.

93. Format of Permit to Work (PTW)/ Line Clear Permit (LCP).

The forms under Appendix F (a) and designated as Requisition for Permit to Work (PTW) shall be used by the requesting Safety Coordinator, who is an authorized person. The form under Appendix F(b) and designated as Check list for Permit To Work and Line Clear Permit shall be used at the time of issue of Line Clear Permit. The form under Appendix F(c) and designated as Permit to Work Return (PWR)/ Line Clear Return (LCR) shall be used for the return of the Line Clear Permit, after the work for which the PTW/ Line Clear Permit was taken is completed. Based on the LCR, the authorized shift in charge of the station who has issued the PTW will cancel the permit and energize the Installation.
94. **Introduction.-**

This part covers the details of requirement for the exchange of information relating to operations and/ or events in the total system, including the Southern grid which have or may have an operational effect on:

(a) The Kerala Grid in case of an operation and/ or event occurring on a user system;

(b) A user system in case of an operation and/ or event in the transmission system;

(c) The procedure for issue of warnings in the event of a risk of serious and widespread disturbances on the whole or part of the Kerala State power grid is set out in this section;

(d) This part applies to SLDC, STU and all entities embedded within the State power system that is under the control and supervision of SLDC.

95. **Periodic Reports.-**

(1) A monthly report covering performance of the State grid shall be prepared by SLDC and made available on its web site. The monthly report shall contain the following:-

1) Frequency profile;

2) Voltage profile of important substations and substations normally having low/ high voltages;

3) Major Generation and Transmission Outages and its restoration time;

4) Transmission constraints;

5) Instances of persistent/ significant non-compliance of State Grid Code;

6) Instances of congestion in transmission system;

7) Instances of inordinate delays in restoration of transmission elements and generating units;

8) Non-compliance of instructions of SLDC by distribution licensees/ users/ EHV consumers to curtail drawal resulting in non compliance of State Grid Code;

9) Total scheduled and actual generation/ drawl of the State;

10) Lines/ Substations operating near thermal rating or rated capacity;

11) Lines/ Substations drawing excessive reactive power;
12) Progress of construction of new generating units, lines and transformers;
13) Details of generation and transmission outages during the month.

(2) A daily report covering the performance of the State grid shall be prepared by SLDC, based on the inputs received from STU, all transmission licensees, all distribution licensees and other Users, and shall be put on its website. This report shall also cover,-
   a) The wind power/ solar power generation and injection into the grid;
   b) Hourly demands met in generation, import, export, voltage, frequency etc.;
   c) Daily consumption, demand and generation during normal/ peak/ off peak/ morning/ day/ evening etc.;
   d) Station wise daily maximum, minimum and average generation (MW), together with daily energy generation.

(3) Daily and monthly reports shall categorize the grid incidents and grid disturbances based on severity of tripping as per clause 11 of the CEA Grid Standards.

96. Other Reports.-
(1) The SLDC shall prepare quarterly reports, which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of various actions taken by different persons, and the persons responsible for causing the constraints and summary of monthly reports.

(2) The SLDC shall also provide information/ report to the State Operation coordination committee of the SGCRC in the interest of smooth operation of STS.

(3) E-mail transmission with password protected read only report file will be considered as written report.

97. Reportable Events.-
Any of the following events require reporting by Users, Distribution licensees, STU to SLDC:

(i) Violation of security standards;
(ii) Grid indiscipline;
(iii) Non-compliance of SLDC’s instructions;
(iv) System islanding/ system split;
(v) Regional black out/ partial system black out;
(vi) Protection failure on any element of STS and on any item on the ‘agreed list’ of the intra State and interstate systems;
(vii) Power system instability;
(viii) Tripping of any element of the State grid;
(ix) Sudden load rejection by any User;
(x) Exceptionally high/ low system voltage or frequency;
(xi) Serious equipment problem relating to major circuit breaker, transformer or bus bar;
(xii) Loss of major Generating Unit;
(xiii) Tripping of Transmission Line, ICT and Capacitor banks;
(xiv) Major fire incidents;
(xv) Force Majeure condition like flooding, lightning etc.
(xvi) Equipment and Transmission Line overload;
(xvii) Accidents- Fatal and Non Fatal;
(xviii) Load Crash/ Loss of Load.

98. Reporting Procedure.-

(1) Written reporting of Events by Users, STU and distribution licensees to SLDC:
   a) In the case of an event which was initially reported by Users, STU and distribution licensees to SLDC orally, the Users, STU and distribution licensees will give a written report to SLDC in accordance with this part.
   b) All reportable incidents occurring on lines and equipment of 33 kV and above and all the lines on which there is inter user flow affecting the State Transmission System shall promptly be communicated by the User whose equipment has experienced the incident (the reporting User) to any other significantly affected Users and to SLDC.
   c) Within one hour of being informed by the Reporting User, SLDC should ask for a written report on the incident.
   d) Reporting User shall submit an initial written report within two hours to SLDC. This has to be further followed up by the submission of a comprehensive report within 48 hours of the submission of the initial written report.
   e) SLDC shall call for a report from any User on any reportable incident affecting other Users and STU, in case the same is not reported by such User whose equipment might have been source of the reportable incident.
   f) The above shall not relieve any User from the obligation to report events in accordance with CEA Safety Regulations.

(2) Written reporting of Events by SLDC to Users, STU and distribution licensees:
   In the case of an event which was initially reported by SLDC to Users, STU and distribution licensees orally, the SLDC will give a written report to the Users, STU and distribution licensees.

(3) The failures of substation apparatus, Transmission line towers and cables of 220kV and above voltage class shall also be reported by the owner of the electrical installation within 48 hours of the occurrence of the failure to the CEA. The reasons for failure and the measures to be taken to avoid recurrence of failure shall also be sent to the CEA within 1 month of the occurrence, in the format given in Schedule IX of the CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, as amended from time to time.

99. Reporting Form.-

The Standard Reporting Form other than for accidents shall be as agreed from time to time by the State Grid Code Review Committee. A written report shall be sent to/ by Users, STU and distribution licensees as the
case may be, in the reporting formats as devised by SLDC and will confirm the oral notification together with the following details of the event:-

(i) Time and date of event;
(ii) Location;
(iii) Plant and/ or Equipment directly involved;
(iv) Description and cause of event;
(v) Antecedent conditions of load and generation, including frequency, voltage and the flows in the affected area at the time of tripping including Weather Condition prior to the event;
(vi) Duration of interruption and Demand and/or Generation (in MW and MWh) interrupted;
(vii) All Relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, Data Acquisition System (DAS) etc.;
(viii) Sequence of tripping with time;
(ix) Details of Relay Flags;
(x) Remedial measures.

A typical form is attached as Appendix-E.

100. Major Failure.-
Following a major failure, SLDC and other Users shall co-operate to inquire and establish the cause of such failure and make appropriate recommendations. SLDC/ STU shall submit the enquiry report to the SGCRC within One month of the incident. The panel shall review the report, prepare suggestion for improving the system/ averting such incidents and submit the final report with recommendations to the Commission within two months.

101. Accident Reporting.-
Reporting of accidents shall be in accordance with Section 161 of the Electricity Act, 2003 and the rules framed there under. Notice of accident and failure of supplies or transmission of electricity shall be in the specified forms, to the Commission and the Electrical Inspector.

102. Performance/ Operational Reporting.-
(1) Every Distribution licensee has to provide annual performance report covering Demand Management (DM), Reactive Power Management and System Operation, pocket wise load forecasting details etc. to STU.
(2) Every generator also have to provide performance report, in terms of PLF, other Key Performance Indicators, including range of maximum and minimum VAR injection and VAR absorption within capability curve etc., in every six months to the STU.
(3) The STU has to provide reports on Operation/ Performance and Planning of network development, annually to the Commission and Distribution Licensees.
(4) SLDC has to provide annual Operation/ Performance report on Grid stability and security to the Commission, STU, Licensees and Generators.
103. Introduction.-

(1) This part specifies the procedure to be adopted for the scheduling and despatch of generation of SGS, CPPs/ IPPs and scheduling of other transactions through long term access, medium term and short term open access including complementary commercial mechanisms, on a day-ahead and intraday basis with the process of flow of information between the SGS/ CPPs/ IPPs, Southern Regional Load Despatch Centre (SRLDC), Power Exchanges, State Load Despatch Centre (SLDC) and other concerned persons to meet system demand and drawal allocation requirements of beneficiaries/ Distribution Licensees. In its control area, SLDC shall have the total responsibility for,-

(i) Scheduling/ despatching of generation from all SGS (including generation of its embedded licensees);
(ii) Regulating the demand of its control area;
(iii) Scheduling their drawal from the ISGS (within its share in the respective plant’s expected capability);
(iv) Permitting long term access, medium term and short term open access transactions for embedded generators/ consumers, in accordance with the contracts; and
(v) Regulating the net drawal of its control area from the regional grid in accordance with the respective Regulations of CERC/ KSERC.

(2) This Part of the State Grid Code deals with the procedures to be adopted for scheduling of the net injection/ drawal of State Entities on day ahead basis with the modality of the flow of information between the SLDC/ Power Exchanges and State Entities. The procedure for submission of capability declaration by each SGS/ CPP/ IPP and submission of requisition/ drawal schedule by other State Entities is intended to enable SLDC to prepare the despatch schedule for each SGS/ CPP/ IPP and drawal schedule for each beneficiary/ Distribution Licensee. It also provides methodology of issuing real time despatch/ drawal instructions and rescheduling, if required, to State Entities along with the commercial arrangement for the deviations from schedules, as well as, mechanism for Reactive Power pricing.

(3) This code also provides the methodology for re-scheduling of Wind and Solar energy generators on 1½ hours basis and the methodology of claiming the Renewable Regulatory Charge for dealing with the variable generation/ handling deviation of such wind and solar energy generators within the State. For this, appropriate meters, telemetry/ communication
system and Data Acquisition System facility (for real time as well as stored data) shall be provided for accounting of charges for deviations under DSM Regulations.

104. Demarcation of Responsibilities,-

The following specific points would be taken into consideration while preparing and finalizing the schedules:

(1) The State grid will be operated as power pools with decentralized scheduling and despatch, in which the State shall have operational autonomy, and SLDC shall have the total responsibility for,-

   a) Scheduling/ dispatching of State’s own generation (including generation of its embedded licensees);
   b) Regulating the demand of its control area;
   c) Scheduling the drawal from the ISGS (within its share in the respective plant’s expected capability);
   d) Permitting long term access, medium term and short term open access transactions for embedded generators/ consumers, in accordance with the contracts;
   e) Regulating the net drawal of its control area from the regional grid in accordance with the respective Regulations of CERC; and
   f) Regulating the net drawal/ injection of each Distribution Licensee and the Users within its control area, as per the schedules.

(2) Certain procedures are to be adopted, while scheduling the generation by State Generating Companies (SGS), Open Access customers, share from Central sector generation and other Licensees, for scheduling the drawal by the beneficiaries of the State on daily basis. The procedure for submission of capability by each Generating Company and submission of drawal schedule by each beneficiary/ Distribution Licensee of the State is intended to enable SLDC to prepare the generation and drawal schedule connected with the system operation. It also provides methodology for issuing real time despatch/ drawal instructions and rescheduling, if required, along with the commercial arrangement for the deviations from schedules.

(3) SLDC will issue despatch instructions required to regulate all generation and imports from SGS (including IPPs, CPPs and Renewable Energy Sources) according to the 15 minutes time block day ahead generation schedule, unless rescheduling is required due to unforeseen circumstances.

(4) In the absence of any despatch instruction by SLDC, SGS shall generate/ export according to the day ahead generation schedule. However, the SLDC shall regulate the overall state generation in such a manner that generation from the following types of power stations where energy potential, if unutilized, goes waste shall not be curtailed:-
a) Run of river or canal based hydro stations;
b) Storage type hydro-stations, when water level is at peak reservoir level or expected to touch peak reservoir level as per inflows or governed by irrigational discharge;
c) Nuclear power stations to avoid poisoning of fuel;
d) Renewable Energy Sources.

(5) Despatch instructions to SGS shall be in standard format to be finalized by SLDC. These instructions will recognize declared availability and other parameters that have been made available by the SGS to SLDC. These instructions shall include time, Power Station, Generating Units (total export in case of CPP), and name of operators sending and receiving the same. Standard despatch instructions may include,-

a) To switch a SGS into or out of Service;
b) To schedule generation;
c) Details of reserve to be carried on a unit;
d) To increase or decrease MVAR generation to maintain voltage profile as per unit capability at that time;
e) To begin pre planned Black Start procedures;
f) To hold spinning reserve;
g) To hold Generating Units of SGS on standby;
h) To control MW/ MVAR Drawal.

(6) The State Load Despatch Centre is responsible for coordinating the scheduling of a generating station within the State, real-time monitoring of the station’s operation, checking that there is no ‘gaming’ in its availability declaration, or in any other way revision of availability declaration and injection schedule, switching instructions, meter data processing, collection/ disbursement of DSM payments, outage planning etc. SLDC shall check that there is no gaming in scheduling by the open access consumers/ licensees. In case, gaming is suspected, SLDC shall disallow the energy corresponding to suspected gaming from DSM account till final decision.

(7) The system of each regional entity shall be treated and operated as a notional control area. The algebraic summation of scheduled drawal from ISGS and from contracts through long term access, medium term and short term open access arrangements shall provide the drawal schedule of each regional entity, and this shall be determined in advance on day ahead basis. The regional entities shall regulate their generation and/or consumer’s load so as to maintain their actual drawal from the regional grid close to the above schedule. Maximum inadvertent deviation allowed during a time block shall not exceed the limits specified in the DSM Regulations. Such deviations should not cause system parameters to deteriorate beyond permissible limits and should not lead to unacceptable
line loading. Inadvertent deviation from net drawal schedule shall be priced through the deviation settlement mechanism as specified by the Central Commission and the State Commission from time to time. Every entity shall ensure reversal of sign of deviation from schedule, at least once after every twelve time blocks.

(8) The SLDC and distribution licensee(s) shall always endeavour to restrict the net drawal of the State from the grid to the drawal schedules, within the limits specified in the DSM regulations. The concerned Distribution Licensee, User and SLDC shall ensure that their Automatic Demand Management System (ADMS) mentioned in clause 5.4.2 of IEGC, acts to ensure that there is no over drawal. If the automatic demand management scheme has not yet been commissioned or not working, then action has to be taken as per manual demand management scheme to restrict the net drawal from the grid within schedules and all actions for early commissioning of Automatic Demand Management System shall be initiated.

(9) The SLDC/ STU/ Distribution Licensees shall regularly carry out the necessary exercises regarding short-term demand estimation for the State/Area, to enable them to plan in advance as to how they would meet their consumer’s load without overdrawing from the drawal schedule.

(10) The SGS, other generating stations and sellers shall be responsible for power generation/ power injection generally according to the daily schedules advised to them by SLDC on the basis of the contracts/requisitions received from SLDC/buyers/Power Exchanges.

(11) The SGS would normally be expected to generate power according to the daily schedules advised to them, barring any inadvertent deviations. Maximum deviation allowed during a time block shall not exceed the limits specified in Deviation Settlement Mechanism Regulations (DSMR). Such deviations should not cause system parameters to deteriorate beyond permissible limits and/or do not lead to unacceptable line loading. Inadvertent deviations, if any, from the ex-power plant generation schedules shall be appropriately priced in accordance with DSM Regulations. In addition, deviations, from schedules causing congestion, shall also be priced in accordance with the CERC (Measures to relieve congestion in real time) Regulations, 2009.

(12) If a generating station is connected only to the State transmission network, SLDC shall coordinate scheduling, except for the Central Generating Stations. Scheduling of generating station supplying power to any State other than the host state will be as provided in the scheduling and dispatch code of IEGC.
(13) If a generating station is connected both to ISTS and the State network, scheduling and other functions performed by the system operator of a control area will be done by SLDC, only if the state has more than 50% share of power. The role of SRLDC, in such a case, shall be limited to consideration of the schedule for interstate exchange of power on account of this ISGS while determining the net drawal schedules of the respective states. If the State has a share of 50% or less, the scheduling and other functions shall be performed by SRLDC.

(14) SLDC may direct the State Entities (beneficiaries or Distribution Licensees)/ SGS to increase/ decrease their drawal/ generation in case of contingencies e.g. overloading of lines/ transformers, abnormal voltages, threat to system security etc. Such directions shall immediately be acted upon. In case the situation does not call for very urgent action, and SLDC has some time for analysis, it shall be checked whether the situation has arisen due to deviations from schedules. These shall be got terminated first through appropriate measures like opening of feeders, if considered necessary by SLDC before an action which would affect the scheduled supplies to the long term, medium term and short term customers is initiated, in accordance with CERC (Grand of connectivity, LTA and MTOA in ISTS and related matters) Regulations, 2009 and CERC (Open Access in ISTS) Regulations, 2008, as amended from time to time. In case STOA or LTA are curtailed, SLDC shall submit a report regarding the reasons due to which, it was not able to curtail deviations from schedule and the agencies which had not taken necessary actions.

(15) In case of interstate bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the Central Electricity Regulatory Commission (Open Access in interstate Transmission) Regulations, 2008 and KSERC (Connectivity and Intra State Open Access) Regulations, 2013, as amended from time to time.

(16) The SGS shall make an advance declaration of ex-power plant MW and MWh capabilities foreseen for the next day, i.e., from 00.00 hrs to 24.00 hrs. During fuel shortage condition, in case of thermal stations, they may specify minimum MW, maximum MW, MWh capability and declaration of fuel shortage. The generating stations shall also declare the possible ramping up/ ramping down in a block. In case of a gas turbine generating station or a combined cycle generating station, the generating station shall declare the capacity for units and modules on APM (Administered Pricing Mechanism) gas, RLNG (Re-gasified Liquefied Natural Gas) and liquid fuel separately, and these shall be scheduled separately.
(17) While making or revising its declaration of capability, except in case of ‘Run of the River’ (with up to three hour pondage) hydro stations, the SGS shall ensure that the declared capability during peak hours is not less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronization of units as a result of forced outage of units.

(18) It shall be incumbent upon the SGS to declare the plant capabilities faithfully, as per their best assessment. In case, it is suspected that they have deliberately over/under declared the plant capability contemplating to deviate from the schedules given on the basis of their capability declarations (and thus make money either as undue capacity charge or as the charge for deviations from schedule), SLDC may serve the ‘notice of gaming’ and ask the SGS to explain the situation with necessary backup data.

(19) The SGS shall be required to demonstrate the declared capability of its generating station as and when asked by SLDC. In the event of the SGS failing to demonstrate the declared capability, the capacity charges due to the generator shall be reduced as a measure of penalty. The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days fixed charges. For the second mis-declaration the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in the geometrical progression over a period of a month.

(20) The STU shall procure and install Special energy meters, communication system etc. on all inter connections between the state entities, Open Access consumers (directly connected to STS) and other identified points for recording of actual net MWh interchanges and MVARh drawal. The installation, operation and maintenance of Special Energy Meters shall be in accordance with Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time. All concerned Users (in whose premises the Special energy meters are installed) shall take meter readings and transmit them to SLDC, at intervals specified by SLDC, in case of manual meter reading mechanism. However, charges incurred will be paid by the respective users.

(21) RTUs at each and every substation should be provided by the owner of the substation in consultation with State Load Dispatch Centre, so that data from the substation may be integrated with the SLDC. Online data from these RTUs shall be made available at SLDC for monitoring purpose.

(22) SLDC must have provision to provide remote consoles for the utilities, who may desire to have access to the remote data pertaining to the utility. ABT scheduling shall also be provided through the remote consoles.
(23) The SLDC shall be responsible for computation of actual net injection/drawal of concerned Users, 15 minutes time block wise, based on the above meter readings. Subsequently, SLDC will prepare and issue the DSM account in accordance with the relevant Regulations. All computations carried out by SLDC shall be open to all entities for checking/verification for a period of 15 days. In case any mistakes/omissions are detected, the SLDC shall forthwith make complete recheck of the data and calculations and rectify the same.

(24) The operating log books of the generating station shall be available for review by the SLDC/SGCRC. These books shall keep the records of machine operation and maintenance.

(25) Hydro generating stations are expected to respond to grid frequency changes and inflow fluctuations.

(26) SLDC shall periodically review the actual deviations from the despatch and net drawal schedules being issued, to check whether any of the state entities are indulging in unfair gaming or collusion. In case such practice is detected the matter shall be reported to Member Secretary of SGCRC, for further investigation.

(27) Scheduling and dispatch procedures for long term, medium term and short term Open Access shall be as per the provisions of Open Access Regulations issued by KSERC and the detailed procedures of STU, as approved by the Commission.

105. Generation and Drawal Scheduling,-

SLDC is responsible for collection, examination and compilation of generation Schedule for each SGS/IPP/ CPP and drawal Schedule for each Distribution Licensee in prescribed manner and at the prescribed time. For scheduling purpose, each day starting from 00.00 hours will be divided into 96 time blocks of 15 minutes interval.

106. Steps in Scheduling,-

Step by step procedure for scheduling of ISGS, SGS/IPP/ CPP, Long term access, Medium term and Short term open access shall be as described below:-

(i) By 06:00 AM every day each SGS shall intimate to SLDC and each ISGS shall intimate to the concerned RLDC, the station wise ex-power plant MW and MWh capabilities foreseen for the next day i.e. between 00.00 to 24.00 hrs of the following day, at 15 minutes interval.

(ii) By 07.00 AM every day each Distribution Licensee shall intimate SLDC the overall requirement in MW and MWh for the next day at 15 minutes interval. Distribution Licensees shall be entitled to a MW
despatch upto (foreseen ex-power plant MW capability for the day) x (Distribution Licensee’s Share in the station’s capacity), for all such stations. In case of hydro-electric stations, there would also be a limit on daily MWh despatch equal to (MWh generation capacity for the day) x (Distribution Licensee’s share in the station’s capacity).

(iii) As per clause 6.5 (3 and 4) of IEGC, the foreseen capabilities of ISGS and the corresponding MW and MWh entitlements available to Kerala, during the following day at 15 minutes intervals shall be compiled by SRLDC and shall be intimated to SLDC and the beneficiaries, as per the provisions of IEGC, by 08:00 AM.

(iv) The original beneficiary shall communicate its consent to the SGS/ISGS by 09.45 AM each day about the quantum and duration of power for next day for sale in the market. The original beneficiary may also provide a standing consent to the SGS/ISGS for sale of power in the market for specified duration and specified quantum.

(v) The SGS/ISGS shall not sell the power of any beneficiary in the market without its express consent. The beneficiary shall not be allowed to schedule the power for which consent has been given by the beneficiary to the SGS/ISGS except in cases where power is still available with the SGS/ISGS after sale through bilateral and collective transactions.

(vi) After receipt of the information in regard to the availability from different sources as per clauses (i) to (iv) above, SLDC shall review aggregate capability of SGS/ISGS and the bilateral interchanges, if any, vis-à-vis Distribution Licensees requirements.

(vii) By 03.00 PM, SLDC shall finalize:
(a) Generation schedule of SGS and
(b) Drawal schedule of each Distribution Licensee.

It shall accordingly advise each Distribution Licensee of their drawal schedule and will work out and convey to SRLDC the net drawal schedule in each of the ISGS along with the bilateral exchanges agreed or intended in their drawal schedule. SLDC will also work out and convey to SRLDC the net drawal schedule to have with the other State/States and the estimate of demand/availability in the State and additional power it would like to draw subject to availability.

107. Scheduling of Collective Transaction,-

(1) a) As per clause 6.5(5) of IEGC, NLDC/ SRLDC shall schedule the collective transaction for the State. Power Exchange(s) shall furnish the interchange on various interfaces/ control areas/ regional transmission systems with the information of total drawal and injection in each of the regions. Based on the information furnished by the Power Exchanges, NLDC shall check for congestion. In case of congestion, NLDC shall inform the Exchanges about the period of congestion and the available
limit for scheduling of collective transaction on respective interface/ control area/ transmission systems during the period of congestion for Scheduling of Collective Transaction through the respective Power Exchanges. The limit for scheduling of collective transaction for respective Power Exchanges shall be worked out in accordance with CERC directives. Based on the application for scheduling of Collective Transaction submitted by the Power Exchange(s), NLDC shall send the details (Scheduling Request of Collective Transaction) to RLDCs for final checking and incorporating them in their schedules. After getting confirmation from RLDCs, NLDC shall convey the acceptance of scheduling of collective transaction to Power Exchange(s). SRLDC shall schedule the Collective Transaction at the periphery of the State.

b) The individual transactions for State Utilities/ intra-state Entities shall be scheduled by the SLDC. Power Exchange(s) shall send the detailed break up of each point of injection and each point of drawal within the State to SLDC, after receipt of acceptance from NLDC. Power Exchange(s) shall ensure necessary coordination with SLDC for scheduling of the transactions.

c) Timeline for above activities will be as per detailed procedure for Scheduling of Collective Transaction issued in accordance with CERC (Open Access in inter-state transmission) Regulations, 2008 and as amended from time to time.

(2) SLDC may also give standing instructions to SRLDC such that SRLDC itself may decide the best drawal schedules for the State.

(3) As per clause 6.5(7) of IEGC, by 06.00 PM, SRLDC shall convey to SLDC the drawal schedule for the State from each of the ISGS. SLDC shall convey to SGS the generation schedule and the drawal schedule to Distribution Licensees by 07.00 PM.

(4) SGS and each Distribution Licensee may inform the modifications/ changes to be made, if any, in the above schedule to SLDC by 09.30 PM.

(5) SLDC after considering the same shall convey any modification/ changes to be made in drawal schedule/ foreseen capabilities, if any, to SRLDC by 10.00 PM or preferably earlier.

(6) On receipt of information and after due consultations, SRLDC shall issue the final generation and drawal schedule for the next day by 11.00 PM, and SLDC shall inform the same to all concerned.

(7) The declaration of the generating capability by hydro SGS should include limitation on generation during specific time periods, if any, on account of restriction(s) on water use due to irrigation, drinking water, industrial, environmental considerations etc. The SLDC shall periodically check that the generating station is declaring the capacity and energy sincerely and is
not manipulating the declaration with the intent of making undue money through DSM.

(8) Since variation of generation in run-of-river power stations shall lead to spillage, these shall be treated as must run stations. All renewable energy power plants, except for biomass power plants with installed capacity of 10 MW and above, and non-fossil fuel based Cogeneration plants whose tariff is determined by the Commission shall be treated as ‘must run’ power plants and shall not be subjected to ‘merit order despatch’ principles. The schedule and dispatch of Biomass power generating stations with installed capacity of >10 MW, Non fossil based Cogeneration projects, Wind and Solar energy projects shall be governed by the provisions in the IEGC and DSM Regulations, as amended from time to time.

(9) Run of the river power stations with pondage and storage type power stations are designed to operate during peak hours to meet system peak demand. Maximum capacity of the station declared for the day shall be equal to the installed capacity including overload capability, if any, minus auxiliary consumption, corrected for the reservoir level. The SLDC shall ensure that generation schedules of such type of SGS are prepared and the schedule despatched for optimum utilization of available hydro energy except in the event of specific system requirements/ constraints.

(10) The schedule finalized by SLDC for hydro SGS, shall normally be such that the scheduled energy for a day equals the total energy (ex-bus) expected to be available on that day, as declared by the generating station, based on foreseen/ planned water availability/ release. It is also expected that the total net energy actually supplied by the generating station on that day would equal the declared total energy, duly meeting the water release requirement.

(11) The SLDC shall prepare the day ahead generation/ drawal schedule keeping in view the following:-

(i) Transmission System constraints from time to time;
(ii) 15 minute load requirements as scheduled by Users i.e. distribution licensees and open access consumers;
(iii) The need to provide operating margins and reserves required to be maintained;
(iv) The availability of generation from SGS, IPPs, CPPs and Central Sector Generators together with any constraint in each case;
(v) Any change in the scheduled quantum of power which are too fast or involve unacceptably large steps may be converted into suitable ramps by SLDC.

108. Revision in injection/ drawal schedule on real time basis.-

During the day of operation, the injection/ drawal schedule may be revised by SLDC under following conditions:
(1) Revision of schedules of SGS, as per the Regulations of KSGC.

(2) SRLDC may revise the schedule of drawal from Southern Region and consequently SLDC shall enforce the revisions within Kerala.

(3) In case of forced outage of a unit of any SGS, SLDC may revise the generation/drawal schedule on the basis of revised declared capability by the affected SGS/Distribution Licensee.

(4) In case of bottleneck in evacuation of power due to any constraint, SLDC may revise the generation/drawal schedule on the basis of revised declared capability by the affected SGS/Distribution Licensee.

(5) As provided in clause 6.5 (16) of IEGC, the revised schedules in case of above contingencies (sub-regulations (3) and (4) above), will become effective from the 4th time block, counting from the time block in which the revision is advised by the generator or in which the bottleneck in evacuation of power has taken place to be the first one. The revised declared capability will also become effective from the 4th time block. Also during the first, second and third time blocks of such an event, the scheduled generation of the station will be deemed to have been revised to be equal to actual generation and also the scheduled drawals of the beneficiaries/Distribution Licensees will be deemed to have been revised accordingly.

(6) In case of any Grid Disturbance, Scheduled Generation of all the Generating Stations supplying power under long term/medium term/short term contracts shall be deemed to have been revised to be equal to their actual generation and Scheduled Drawal of the Beneficiaries/Distribution Licensees shall be deemed to have been revised accordingly for all the time blocks affected by the Grid Disturbance. Certification of Grid Disturbance and its duration shall be done by SLDC. The declaration of disturbance shall be done by SLDC at the earliest. A notice to this effect shall be posted at its website by SLDC. Issue of notice at SLDC website shall be considered as declaration of the disturbance by SLDC. All State entities shall take note of the disturbance and take appropriate action at their end.

(7) As provided in clause 6.5 (18) of IEGC, Revision of declared capability by the SGS(s) having two part tariff with capacity charge and energy charge (except hydro stations) and requisition by beneficiaries/Distribution Licensees for the remaining period of the day shall also be permitted with advance notice. Revised schedules/declared capability in such cases shall become effective from the 4th time block, counting the time block in which the request for revision has been received in the SLDC to be the first one.

(8) Notwithstanding anything contained in sub-regulation (7) above, in case of forced outage of a unit, for those stations who have a two part tariff based on capacity charge and energy charge for long term and medium term contracts, SLDC shall revise the schedule on the basis of revised declared capability. The revised declared capability and the revised schedules shall become effective from the fourth time block, counting the time block in which the revision is advised by the SGS to be the first one.

(9) Notwithstanding anything contained in sub-regulation (7), in case of
forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under Short Term bilateral transaction (excluding collective transactions through power exchange), the generator or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised accordingly. The revised schedules shall become effective from the 4th time block, counting the time block in which the forced outage is declared to be the first one. The SLDC shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit. However, the transmission charges as per original schedule shall continue to be paid for two days:

Provided that the schedule of the buyers and sellers (except the generating stations) shall be revised after forced outage of a unit, only if the source of power for a particular transaction has clearly been indicated during short term open access application and the said unit of that generating station goes under forced outage.

(10) In case of revision of schedule of a generating unit, the schedules of all transactions under the long term access, medium term open access and short term open access (except collective transactions through power exchange), shall be reduced on pro-rata basis:

Provided that the generator or trading licensee or any other licensee selling power from the generating station or unit(s) thereof may revise its estimated restoration time once in a day and the revision shall become effective from the 4th time block, counting the time block in which the revision is advised by the generator to be the first one.

(11) If, at any point of time, SLDC observes that there is need for revision of the schedules in the interest of better system operation, it may do so on its own and in such cases, the revised schedules shall become effective from the 4th time block, counting the time block in which the revised schedule is issued by SLDC to be the first one.

(12) To discourage frivolous revisions, SLDC may, at its sole discretion, refuse to accept schedule/ capability changes of less than two (2) percent of previous schedule/ capability. The schedule of thermal generating stations indicating fuel shortage while intimating the Declared Capacity to the SLDC shall not be revised except in case of forced outage of generating unit:

Provided that in case of gas based generating stations, for optimum utilization of gas, this shall be permitted, i.e. in case of tripping of a unit, this gas may be diverted to another unit using the same gas.

(13) The SLDC shall also formulate the procedure for meeting contingencies both in long term and in the short term (daily scheduling).

109. Special dispensation for Scheduling of Wind and Solar generation,-

(1) Wind and Solar generators shall mandatorily provide to SLDC, in a format as prescribed by SLDC, the technical specifications at the beginning and
whenever there is any change. The data relating to power system parameters and weather related data as applicable shall also be mandatorily provided by such generators to SLDC in real time. The frequency of providing this and other details in this regard shall be as per the Detailed Procedure/ Rules approved by CERC/ Commission.

(2) Forecasting shall be done by Wind and Solar generators as well as the SLDC, for an aggregated generation capacity of 50 MW and above connected at a pooling point. SLDC may engage forecasting agency (ies) and prepare a schedule for such generating stations. The forecast by SLDC shall be with the objective of ensuring secure grid operation. The forecast by the wind and solar generator shall be generator centric. The wind and solar generators which are regional entities will have the option of accepting the SLDC’s forecast for preparing its schedule or provide the SLDC with a schedule based on its own forecast. Any commercial impact on account of deviation from schedule based on the forecast chosen by the wind and solar generator shall be borne by it.

(3) The schedule by wind and solar generators (excluding collective transactions) may be revised by giving advance notice to SLDC. Such revisions shall be effective from 4\(^{th}\) time block, the first being the time block in which notice was given. There may be one revision for each time slot of one and half hours starting from 00:00 hours of a particular day subject to maximum of 16 revisions during the day.

(4) The schedule of solar generators shall be given by the generator based on availability of the generator, weather forecasting, solar insolation/irradiance, season and normal solar generation curve.

(5) The wind and solar generators shall forecast renewable energy generation at the following time intervals,-

(i) Day ahead forecast: Wind and Solar energy generation forecast with an interval of 15 minutes for the next 24 hours for the aggregate generation capacity of 50 MW and above;

(ii) The schedule by such wind and solar generators, supplying inter-state power under long term access or medium term open access or short term open access may be revised by giving advance notice to SLDC. Such revisions shall be effective from 4\(^{th}\) time-block, the first being the time block in which notice was given. There may be one revision for each time slot of one and half hours starting from 00:00 hours of a particular day subject to maximum of 16 revisions during the day.

(6) The charges payable for deviation from schedule by the wind and solar generators shall be delinked from frequency and shall be accounted for and settled in accordance with the provisions of the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2014, as amended from time to time.
(7) Generation schedules and drawal schedules issued/ revised by SLDC shall become effective from designated time block irrespective of communication success.

(8) For any revision of scheduled generation, including post facto deemed revision; there shall be a corresponding revision of scheduled drawals of the beneficiaries.

(9) While finalizing the drawal and despatch schedules as above, the SLDC shall also check that the resulting power flows do not give rise to any transmission constraint. In case any impermissible constraints are foreseen, the SLDC shall moderate the schedules to the required extent, under intimation to the concerned Users.

(10) On completion of the operating day, by 24.00 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of generating stations and drawal schedule of the Users) shall be issued by SLDC by placing it on web site and conveying it on e-mail-id registered with SLDC. This schedule shall be the datum for commercial accounting. The average ex-bus capability for each of the generating stations shall also be worked out based on all before-the-fact advice to SLDC.

(11) The SLDC shall properly document all the above information i.e. station-wise foreseen ex-power plant capabilities advised by the generating stations, the drawal schedule indented by the beneficiaries/ Distribution Licensees, all schedules issued by SLDC and all revisions/ updating of the above.

(12) The procedure for scheduling carried out by SLDC and the final schedules issued by SLDC shall be open to all Users for any checking/ verification, for a period of 5 days. In case any mistake/ omission is detected by SLDC or pointed out by User, the SLDC shall forthwith make a complete recheck and rectify the same.

(13) Procedure for recording the communications for changes to schedules duly taking into account the time factor shall be evolved by STU/ SLDC.

(14) While availability declaration by SGS shall have a resolution of one decimal (0.1) MW and one decimal (0.1) MWh; all entitlements, requisitions and schedules shall be rounded off to the nearest two decimal for each of the transaction, to have a resolution of (0.01) MW.

110. Scheduling and Commercial Settlement of energy exchanged under Ancillary Services including Spinning Reserves and URS,-

(1) The Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 provides detailed frame work of scheduling and despatch, withdrawal, energy accounting and commercial settlement of
Reserves Regulating Ancillary Services.

(2) In case of spinning reserves, the scheduling and commercial settlement of energy exchanged shall be as per the Detailed Procedure notified by CERC.

(3) In case of sale of share of original beneficiaries in market by ISGS/ SGS for which consent has been given, the realized gains shall be shared between the ISGS/ SGS and the concerned beneficiary in the ratio of 50:50 or as mutually agreed by the ISGS/ SGS and the concerned beneficiary, in the billing of the following month. This gain shall be calculated as the difference between selling price of such power and fuel charge including incidental expenses:

Provided that such sale of power by SGS shall not result in any adverse impact on the original beneficiary (ies) including in the form of higher average energy charge vis-à-vis the energy charge payable without such sale:

Provided further that there shall be no sharing of loss between the SGS and the beneficiary (ies):

Provided also that, the liability of fixed charge in such cases shall remain with the original beneficiary (ies) as determined in accordance with the Tariff Regulations notified by the Commission from time to time.

111. Generation Despatch,-

(1) SGS shall comply promptly with a dispatch instruction issued by SLDC unless this action would compromise the safety of plant or personnel. SGS shall promptly inform SLDC in the event of any unforeseen difficulties in carrying out an instruction.

(2) Despatch instructions shall be issued by E-mail/ Fax/ Telephone, confirmed by exchange of name of operators sending and receiving the same and logging the same at each end. All such oral instructions shall be complied forthwith and written confirmation shall be issued promptly by FAX, tele-printer or otherwise.

112. Enhancement of Schedule and Despatch Procedure,-

The Schedule and dispatch procedures shall be suitably enhanced by SLDC to cater to tariff agreements, as soon as such agreements are reached with SGS. All Distribution Licensees/ State utilities/ Consumers / IPPs/ CPPs etc. shall keep SLDC informed about any changes in existing Agreements or additional Agreements.
113. Introduction.-
(1) This part describes the procedure for declaration of the ‘Date of Commercial Operation’ (COD) of intra state generating stations, transmission systems, associated Communication systems, fixing the technical minimum schedules for operation of intra state generating stations and the compensation thereof.

(2) The objectives of this part are:
   a) to define the COD of an Intra State Thermal/ Hydro Generating Station;
   b) to define the Trial Run/ Operation of an Intra State Thermal/ Hydro Generating Station/ State Transmission system;
   c) to define the COD of the Communication system/ Transmission system of the State Transmission Licensee;
   d) to define the Technical Minimum Schedule for operation of SGS and compensation thereof.

114. Date of Commercial Operation (COD) of Thermal generating station,-
(1) Date of commercial operation in case of a unit of intra State Thermal Generating Station shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its Maximum Continuous Rating (MCR) or the Installed Capacity (IC) or Name Plate Rating, on designated fuel through a successful trial run and after getting clearance from the SLDC, and in case of the generating station as a whole, the date of commercial operation of the last unit of the generating station:
   Provided that,-
   (i) Where the beneficiaries/ buyers have been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries/ buyers and SLDC;
   (ii) Where the beneficiaries/ buyers have not been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the SLDC.

(2) The generating company shall certify that,-
   a) The generating station meets the relevant requirements and provisions of the Technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines)
Regulations, 2010, Indian Electricity Grid Code and this Code, as applicable;
b) The main plant equipment and auxiliary systems including Balance of Plant, such as Fuel Oil System, Coal Handling Plant, Demineralization plant, pre-treatment plant, fire fighting system, Ash Disposal system and any other site specific systems have been commissioned and are capable of full load operation of the units of the generating station on sustained basis;
c) Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of unit have been put in service.

(3) The certificates as required under sub-regulations above shall be signed by the CMD/ CEO/ MD of the generating company and a copy of the certificate shall be submitted to SLDC before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates within a period of 3 months of the COD.

(4) Trial run shall be carried out in accordance with Regulation 116 of this Code.

(5) Partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating or the Installed Capacity or the Name Plate Rating excluding period of interruption and partial loading but including the corresponding extended period.

(6) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to Maximum Continuous Rating or Installed Capacity or Name Plate Rating, the generating company has the option to de-rate the capacity or to go for repeat trial run. Where the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 105% of de-rated capacity.

(7) The SLDC shall convey clearance to the generating company for declaration of COD within 7 days of receiving the generation data based on the trial run.

(8) If the SLDC notices any deficiencies in the trial run, it shall be communicated to the generating company within seven (7) days of receiving the generation data based on the trial run.

(9) The Scheduling of power from the generating station or unit thereof shall commence from 00.00 hrs after declaration of COD.
115. Date of Commercial Operation of Hydro Generating Station,-

(1) Date of commercial operation (COD) in relation to a generating unit of hydro generating station including pumped storage hydro generating station shall mean the date declared by the generating company after demonstrating peaking capability corresponding to the Installed Capacity of the generating station through a successful trial run, and after getting clearance from the SLDC, and in relation to the generating station as a whole, the date of commercial operation of the last generating unit of the generating station:
Provided that,-

(i) Where beneficiaries have been tied up for purchasing power from the generating station, trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and SLDC:

(ii) Where the beneficiaries/buyers have not been tied up for purchasing power from the generating station, the trial run shall commence after a notice of not less than seven days by the generating company to SLDC.

(2) The generating company shall certify that,-

(a) The generating station or unit thereof meets the requirement and relevant provisions of the technical standards of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010, Indian Electricity Grid Code and this code, as applicable,-

(b) The main plant equipment and auxiliary systems including Drainage Dewatering system, Primary and Secondary cooling system, LP and HP air compressor, Fire fighting system etc. have been commissioned and are capable for full load operation of units on sustained basis,-

(c) Permanent electric supply system including emergency supplies and all necessary Instrumentation, Control and Protection Systems and auto loops for full load operation of the unit are put into service.

(3) The certificates as required above shall be signed by the CMD/ CEO/ MD of the generating company and a copy of the certificate shall be submitted to the SLDC, before declaration of COD. The generating company shall submit approval of Board of Directors to the certificates within a period of 3 months of COD.

(4) Trial run shall be carried out in accordance with Regulation 116 of this Code.

(5) Where on the basis of the trial run, a unit of the generating station fails to demonstrate the unit capacity corresponding to Maximum Continuous Rating or Installed Capacity or Name Plate Rating, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the demonstrated capacity in such cases shall be more or equal to 110% of derated capacity.
(6) In case a hydro generating station with pondage or storage is not able to demonstrate the peaking capability corresponding to the installed capacity for the reason of insufficient reservoir or pond level, the date of commercial operation of the last unit of the generating station shall be considered as the date of commercial operation of the generating station as a whole, and it will be mandatory for such hydro generating station to demonstrate peaking capability equivalent to installed capacity of the generating station or unit thereof as the case may be, as and when such reservoir/ pond level is achieved.

(7) If a run-of-river hydro generating station or a unit thereof is declared under commercial operation during lean inflows period when the water inflow is insufficient for such demonstration of peaking capability, it shall be mandatory for such hydro generating station or unit thereof to demonstrate peaking capability equivalent to installed capacity as and when sufficient water inflow is available. In case of failure to demonstrate the peaking capacity, the unit capacity shall be de-rated to the capacity demonstrated with effect from the COD.

(8) The SLDC, shall accord clearance to the generating company within seven (7) days of receiving the generation data based on the trial run.

(9) If the SLDC notices any deficiency in trial run, it shall be communicated to the generating company within seven (7) days of receiving the generation data based on trial run.

(10) Scheduling shall commence from 00.00 hrs after declaration of COD.

116. Trial Run or Trial Operation,-

(1) Trial Run or Trial Operation in relation to a thermal Intra State Generating Station or a unit thereof shall mean successful running of the generating station or unit thereof on designated fuel at Maximum Continuous Rating or Installed Capacity or Name Plate Rating for a continuous period of 72 hours and in case of a hydro intrastate Generating Station or a unit thereof for a continuous period of 12 hours:

Provided that,-

The short interruptions, for a cumulative duration of 4 hours, shall be permissible, with corresponding increase in the duration of the test. Cumulative Interruptions of more than 4 hours shall call for repeat of trial operation or trial run;

(2) The partial loading may be allowed with the condition that average load during the duration of the trial run shall not be less than Maximum Continuous Rating, or the Installed Capacity or the Name Plate Rating excluding period of interruption and partial loading but including the corresponding extended period.

(3) Where the beneficiaries have been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries and SLDC.
Units of thermal and hydro Central Generating Stations and inter State Generating Stations shall also demonstrate capability to raise load upto 105% or 110% of this Maximum Continuous Rating or Installed Capacity or the Name Plate Rating as the case may be.

117. **Date of Commercial Operation of STS**

1. **Date of commercial operation in relation to an intra State Transmission System or an element thereof** shall mean the date declared by the transmission licensee from 00.00 hour of which an element of the transmission system is in regular service after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end:

   Provided that in the case of intra State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee shall declare COD of the STS in accordance with the provisions of the Transmission Service Agreement.

2. Where the transmission line or substation is dedicated for evacuation of power from a particular generating station and the dedicated transmission line is being implemented other than through tariff based competitive bidding, the concerned generating company and transmission licensee shall endeavour to commission the generating station and the transmission system simultaneously as far as practicable and shall ensure the same through appropriate Implementation Agreement in accordance with relevant provisions of the Kerala State Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2018 or any subsequent amendment thereto or re-enactment thereof. In case the transmission line or substation dedicated to a generator is being implemented through tariff based competitive bidding, then matching of commissioning of the transmission line/substation and generating station shall be monitored by STU and SLDC.

3. Where the transmission system executed by a transmission licensee is required to be connected to the transmission system executed by any other transmission licensee and both transmission systems are executed in a manner other than through tariff based competitive bidding, the transmission licensee shall endeavour to match the commissioning of its transmission system with the transmission system of the other licensee as far as practicable and shall ensure the same through an appropriate Implementation Agreement. Where either of the transmission systems or both are implemented through tariff based competitive bidding, the progress of implementation of the transmission systems in a matching time schedule shall be monitored by STU/SLDC.

4. In case a transmission system or an element thereof is prevented from regular service on or before the Scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors,
but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate application for approval of the date of commercial operation of such transmission system or an element thereof.

(5) An element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as per the Transmission Service Agreement are commissioned. In case any element is required to be commissioned prior to the commissioning of pre-required element, the same can be done if STU/ SLDC confirm that such commissioning is in the interest of the power system.

(6) The transmission licensee shall submit a certificate from the CMD/ CEO/ MD of the Company that the transmission line, substation and communication system conform to the relevant Grid Standard and Grid Code, and are capable of operation to their full capacity.

(7) Trial run and Trial operation in relation to a transmission system or an element thereof shall mean successful charging of the transmission system or an element thereof for 24 hours at continuous flow of power, and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system in service enclosing certificate to that effect from the SLDC.

118. **Date of Commercial Operation in relation to a Communication System** or an element thereof shall mean the date declared by the transmission licensee from 00.00 hour of which a communication system or element thereof shall be put into service after completion of site acceptance test including transfer of voice and data to respective control centre as certified by the State Load Dispatch Centre.

119. **Date of Commercial Operation in relation to a Wind/ Solar Project.** COD shall be considered as the actual date of commissioning of the project as declared by the committee consisting of members of State Nodal Agency, STU and the Developer. In case of part commissioning, COD will be declared only for that part of the project capacity. The following two distinct milestone dates for commissioning shall be observed:-

i) Inter connection with the Grid: This shall be provided by the STU/ Transmission Licensee on the request of the Developer, to facilitate testing and flow of energy;

ii) Commissioning of the Project: This will be the date when the Project meets the criteria for commissioning as declared by the committee;
iii) The power injected into the grid till COD shall be considered as infirm power.

120. The Infirm power injected into the grid by a generating unit upto the COD shall be accounted at half the tariff approved for the SGS or as per the conditions agreed in the PPA:
Provided that in the event of inconsistency between the provisions relating to Trial operation and Commercial operation as specified in these Regulations of this Code and the provisions of Kerala State Electricity Regulatory Commission (Terms and Conditions of Tariff) Regulations, 2018 or any subsequent enactment thereof, the provisions of this Code shall prevail.

121. Technical Minimum Schedule for Operation of SGS.-

(1) The technical minimum for operation in respect of a unit or units of an intra State Generating Station shall be 55% of MCR loading or installed capacity of the unit or units of the generating station.

(2) The SGS may be directed by SLDC to operate its unit(s) at or above the technical minimum but below the normative plant availability factor on account of grid security or due to the fewer schedules given by the beneficiaries.

(3) Where the SGS, whose tariff is either determined or adopted by the Commission, is directed by the SLDC to operate below normative plant availability factor but at or above technical minimum, the SGS may be compensated depending on the average unit loading duly taking into account the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption etc. on monthly basis, duly supported by relevant data verified by SLDC:
Provided that,-
(i) In case of coal/ lignite based generating stations, following station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation,-

<table>
<thead>
<tr>
<th>Sl. No.</th>
<th>Unit loading as a % of Installed Capacity of the Unit</th>
<th>Increase in SHR (for supercritical Units) (%)</th>
<th>Increase in SHR (for sub-critical Units) (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>85-100</td>
<td>Nil</td>
<td>Nil</td>
</tr>
<tr>
<td>2</td>
<td>75-84.99</td>
<td>1.25</td>
<td>2.25</td>
</tr>
<tr>
<td>3</td>
<td>65-74.99</td>
<td>2</td>
<td>4</td>
</tr>
<tr>
<td>4</td>
<td>55-64.99</td>
<td>3</td>
<td>6</td>
</tr>
</tbody>
</table>
(ii) In case of coal/ lignite based generating stations, the following Auxiliary Energy Consumption (AEC) degradation or actual, whichever is lower shall be considered for the purpose of compensation:

<table>
<thead>
<tr>
<th>Sl. No</th>
<th>Unit Loading (% of MCR)</th>
<th>% Degradation in AEC admissible</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>85 – 100</td>
<td>Nil</td>
</tr>
<tr>
<td>2</td>
<td>75 – 84.99</td>
<td>0.35</td>
</tr>
<tr>
<td>3</td>
<td>65 – 74.99</td>
<td>0.65</td>
</tr>
<tr>
<td>4</td>
<td>55 - 64.99</td>
<td>1.00</td>
</tr>
</tbody>
</table>

(iii) Where the scheduled generation falls below the technical minimum schedule, the concerned SGS shall have the option to go for reserve shut down and in such cases, start-up fuel cost over and above seven (7) start/ stop in a year shall be considered as additional compensation based on following norms or actual, whichever is lower:

<table>
<thead>
<tr>
<th>Unit Size (MW)</th>
<th>Oil Consumption per start up (KL)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Hot</td>
</tr>
<tr>
<td>200/210/250</td>
<td>20</td>
</tr>
<tr>
<td>500</td>
<td>30</td>
</tr>
<tr>
<td>660</td>
<td>40</td>
</tr>
</tbody>
</table>

(iv) In case of gas based intra State Generating Station, compensation shall be decided based on the characteristic curve provided by the manufacturer and after prudence check of the actual operating parameters of Station Heat Rate, Auxiliary Energy Consumption etc.

(v) Compensation for the Station Heat Rate and Auxiliary Energy Consumption shall be worked out in terms of energy charges.

(vi) The compensation so computed shall be borne by the entity that has caused the plant to be operated at schedule lower than corresponding to Normative Plant Availability Factor up to technical minimum based on the compensation mechanism finalized by SLDC.

(vii) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and/ or actual Auxiliary Energy Consumption are lower than the normative Station Heat Rate and/ or normative Auxiliary Energy Consumption applicable to the unit or the generating station.

(viii) There shall be reconciliation of the compensation at the end of the financial year in due consideration of actual weighted average operational parameters of station heat rate, auxiliary energy
consumption and secondary oil consumption.

(ix) No compensation for Heat Rate degradation and Auxiliary Energy Consumption shall be admissible if the actual Heat Rate and/or actual Auxiliary Energy Consumption are lower than the normative station Heat Rate and/or normative Auxiliary Energy Consumption applicable to the unit or the generating station in a month or after annual reconciliation at the end of the year.

(x) The change in schedule of power under the provisions of Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 shall not be considered for compensation.

(4) In case of a generating station whose tariff is neither determined nor adopted by the Commission, the concerned generating company shall have to factor the above provisions in the PPAs entered into by it for sale of power in order to claim compensation for operating at the technical minimum schedule.

(5) The generating company shall keep the record of the emission levels from the plant due to part load operation and submit a report for each year to the Commission by 31st May of the year.

(6) Detailed Operating Procedure of the generating stations containing the role of different agencies, data requirements, procedure for taking the units under reserve shut down and the methodology for identifying the generating stations or units thereof to be backed down up to the technical minimum in specific Grid conditions such as low system demand, Regulation of Power Supply and incidence of high renewables etc., based on merit order stacking shall be as per the regulations/guidelines/procedures issued by CERC/Commission from time to time.

(7) SLDC/CMC shall work out a mechanism for compensation for station heat rate and auxiliary energy consumption for low unit loading on monthly basis in terms of energy charges and compensation for secondary fuel oil consumption over and above the norm of 0.5 ml/kWh for additional start-ups in excess of 7 start-ups, in consultation with generators and beneficiaries and its sharing by the beneficiaries, as per the guidelines provided in Appendix II of CERC order dated 5th May 2017 in this matter.
Part XII

FREQUENCY, VOLTAGE and REACTIVE POWER MANAGEMENT

122. Introduction.-
(1) This part describes the method by which all Users of the State Transmission System shall co-operate with SLDC and STU to ensure effective control of the system frequency and for managing the voltage of the State Transmission System.

(2) The STS normally operates in synchronism with the Southern Grid and SRLDC has the overall responsibility of the integrated operation of the Southern Regional Power System. The constituents of the Region are required to follow the instructions of SRLDC for backing down generation, regulating loads, MVAR drawal etc. to meet the objective.

(3) SLDC shall accordingly instruct Generating Units to regulate Generation/Export and hold reserves of active and reactive power within their respective declared parameters. SLDC shall also regulate the load as may be necessary to meet the objective.

(4) The State Transmission System voltage levels can be affected by Regional operation. The STU/SLDC shall optimize voltage management by adjusting transformer taps (On Line Tap Changers) to the extent available and switching of circuits/capacitors/reactors and other operational steps. SLDC will instruct SGS to regulate MVAR generation within their declared parameters. SLDC shall also instruct Distribution Licensees to regulate demand, if necessary.

(5) The objectives of this part are as follows:-
   a) To define the responsibilities of all Users in contributing to frequency and voltage management;
   b) To define the actions required to enable SLDC and STU to maintain the State Transmission System voltages and frequency within acceptable levels in accordance with IEGC guidelines as well as Planning and Security Standards for the State Transmission System specified by the Commission, if any;

123. Responsibilities.-
(1) SLDC shall monitor actual power drawal against scheduled power drawal and regulate internal generation and demand to maintain this schedule. SLDC shall also monitor reactive power drawal and availability of capacitor banks.

(2) Generating Stations within the State of Kerala other than ISGS shall follow the despatch instructions issued by SLDC.

(3) Distribution licensees, Open Access Customers and other Users shall
comply with the instructions of SLDC for managing load and reactive power drawal as per system requirement.

124. **Frequency Management**.-

(1) The rated frequency of the system shall be 50 Hz and shall normally be regulated within the limits prescribed in IEGC. STU and SLDC as constituent of Southern Region shall make all possible efforts to ensure that grid frequency remains within 49.95 – 50.2 Hz band.

(2) **Falling frequency**,-

a) SLDC/ distribution licensee and EHV consumer shall initiate action to restrict the drawal of its control area, from the grid, within the net drawal schedule whenever the system frequency falls below 50 Hz. The SLDC/ distribution licensee and EHV consumer shall ensure that their automatic demand management scheme mentioned in Regulation 72 acts to ensure that there is no over drawl when frequency is below 50 Hz. If the automatic demand management scheme has not yet been commissioned, then action has to be taken as per manual demand management scheme to ensure zero over drawal when frequency is 50 Hz or below.

b) The SLDC/ STU/ Distribution Licensees shall regularly carry out the necessary exercises regarding short term demand estimation for their respective State/ Area, to enable them to plan in advance as to how they would meet their consumer’s load without overdrawning from the grid.

(3) **Rising Frequency**.-

When the frequency is above 50.2 Hz, the SGS may (at their discretion) back down upto 5% or higher value (if pre-advised by SLDC) without waiting for an advice from SLDC to restrict the frequency rise. When the frequency falls below 50 Hz, the generation at all SGS (except those on peaking duty) shall be maximized, at least upto the level to which can be sustained, without waiting for an advice from SLDC subject to the condition that such increase does not lead to unacceptable line loading or system parameters to deteriorate beyond permissible limit.

125. **Voltage Management**.-

(1) Users using the State Transmission System shall make all possible efforts to ensure that the grid voltage always remains within the limits specified at Regulation 47(6).

(2) STU and/ or SLDC shall carry out load flow studies based on operational data from time to time to predict where voltage problems may be encountered and to identify appropriate measures to ensure that voltages remain within the defined limits. On the basis of these studies, SLDC shall instruct SGS to maintain specified voltage level at interconnecting points. SLDC and STU shall co-ordinate with the Distribution Licensees to
determine voltage level at the interconnection points. SLDC shall continuously monitor 400/ 220/ 110/ 66/ 33 kV voltage levels at strategic substations.

(3) SLDC shall take appropriate measures to control State Transmission System voltages, which may include but not be limited to transformer tap changing, capacitor/ reactor switching including capacitor switching by Distribution Licensees at 66 kV and 33 kV substations, operation of Hydro unit as synchronous condenser and use of MVAR reserves with SGS within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

(4) SGS (except CPPs) shall make available to SLDC the up to date capability curves for all Generating Units, as detailed in Part III, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to/ Import from State Transmission System.

(5) Distribution licensees, Open Access Customers and other users shall participate in voltage management by providing Local VAR compensation (as far as possible in low voltage system close to load points) such that they do not depend upon EHV grid for reactive support.

126. Reactive Power Management.

(1) Reactive Power compensation should ideally be provided locally by generating Reactive Power as close to the Reactive Power consumption as possible. The beneficiaries are therefore expected to provide local VAR compensation/ generation such that they do not draw VAR from the state grid particularly under low voltage conditions. However, considering the present limitations this is not being insisted upon. Instead, to discourage VAR drawings by beneficiaries, VAR exchanges with intra state transmission system shall be priced as follows:

(a) The beneficiary pays for VARh drawal when voltage at the metering point is below 97%;
(b) The beneficiary gets paid for VARh returns when voltage is below 97%;
(c) The beneficiary gets paid for VARh drawal when voltage is above 103%;
(d) The beneficiary pays for VARh return when voltage is above 103%.

(2) The charge/ payment for VAR shall be at a nominal paise/ kVARh rate as may be specified by the Central Electricity Regulatory Commission from time to time for interstate transactions, and will be between the beneficiary and the State Pool Account for VAR interchanges.
Notwithstanding the above SLDC may direct a beneficiary to curtail its VAR drawal/ injection in case the security of grid or safety of any equipment is endangered.

(3) The SLDC may issue direction to any generator within the State to increase VAR generation/ absorption upto the machine capability limit. In general the beneficiaries shall endeavour to minimize the VAR drawal at an interchange point when the voltage at that point is below 95% of the rated voltage and shall not return VAR when the voltage is above 105%. Transformer taps at the respective drawal points may be changed to control the VAR interchanges as per the beneficiary’s request to SLDC, but only at reasonable intervals. A beneficiary may also request the SLDC for increase/decrease of VAR generation at a generating station for addressing a voltage problem.

(4) Switching in/ out of all bus and line reactors throughout the state grid shall be carried out as per instructions of SLDC. Tap changing on all interconnecting transformers in STU system shall also be done as per SLDC’s instructions. The SLDC shall monitor the working of shunt capacitor banks installed in the substations of STU/ transmission licensee/ Distribution substations and direct them to switch in/out as and when required.

(5) The generating station shall change generator transformer taps and generate/ absorb Reactive Power as per the instructions of SLDC, within capability limits of the respective generating units, that is, without sacrificing the active generation required at that time. No payments shall be made to the generating companies for such VAR generation/ absorption.

(6) VAR exchanges directly between two entities except generating stations on the interconnecting lines generally addresses or cause a local voltage problem, and generally do not have an impact on the voltage profile of the State grid. Accordingly the management/ control and commercial handling of the VAR exchanges on such lines shall be as per the following provisions on case by case basis:-

(i) The two concerned entities may mutually agree not to have any charge/ payment for VAR exchanges between them on an interconnecting line.

(ii) The two concerned entities may mutually agree to adopt a payment rate/ scheme for VAR exchanges between them identical to or at variance from that specified by CERC/ KSERC for VAR exchanges with the state transmission system. If the agreed scheme requires any additional metering, the same shall be arranged by the concerned beneficiaries.
(iii) The computation and payments for such VAR exchanges shall be effected as mutually agreed between the two beneficiaries.

(7) In case of a disagreement between the concerned entities (e.g. one party wants to have the charge/ payment for VAR exchanges, and the other party refuses to have the scheme), the scheme as specified in Appendix G shall be applied.

(8) The rate/ charges for VARh exchange shall be as specified by CERC/ KSERC from time to time.

(9) SLDC shall issue the monthly statement for VAR charges, to all intra state entities that have a net drawal/ injection of reactive energy under low/ high voltage conditions. These payments shall also have a high priority and the concerned entities shall pay the indicated amounts into the state reactive pool account operated by the SLDC within 10(ten) days of statement issue, provided that the Commission may direct any entity other than SLDC to operate the state reactive pool account. The intra state entities who have to receive the money on account of VARh charges would then be paid out from the state reactive pool account, within two (2) working days from the receipt of payment in the State Reactive pool account.

(10) If payment against the above VAR charges is delayed by more than two days i.e. beyond twelve (12) days from statement issue, the defaulting entity shall have to pay simple interest @0.04% for each day of delay. The interest so collected shall be paid to the entities that had to receive the amount, payment of which got delayed. Persistent payment defaults, if any, shall be reported by SLDC to the Commission for initiating remedial action.

(11) The money remaining in the state reactive account after pay out of all VARh charges upto 31st March of every year shall be utilized for training of the SLDC operators and other similar purposes which would help in improving/ streamlining the operation of the state grid as decided by the Commission from time to time.

(12) In case the voltage profile of the state grid improves to an extent that the total pay-out from the state VAR charges account for a month exceeds the total amount being paid-in for that month and if the state reactive account has no balance to meet the deficit, the pay-outs shall be proportionately reduced according to the total money available in the above account.

(13) The SLDC shall table the complete statement of the state reactive energy pool account annually to the Commission for audit.
Part XIII

MONITORING OF GENERATION and DRAWAL

127. Introduction.-

The monitoring of SGS output and Active and Reactive reserve capacity is important to evaluate the performance of generation plants. The monitoring of actual drawal against schedule is important to ensure that STU and Distribution Licensees contribute towards improving system performance and observe Grid discipline.

128. Monitoring Procedure.-

(1) For effective operation of the State Transmission System, it is important that a SGS’s declared availability is realistic and that any departures are continually and invariably fed back to the Generator, to enable it to effect improvement.

(2) The SLDC shall continuously monitor Generating Unit outputs and Bus voltages. More stringent monitoring may be performed at any time when there is reason to believe that a SGS’s declared availability may not match the actual availability or declared output does not match the actual output.

(3) SLDC can ask for putting a generating station to demonstrate the declared availability by instructing the generating station to come up to the declared availability within time specified by generators.

(4) SLDC shall inform a SGS, in writing, if the continuous monitoring of the station demonstrates an apparent persistent or material mismatch between the despatch instructions and the Generating Unit output or breach of the Connection Conditions. Continued discrepancies shall be resolved by the SGCRC with a view to either improve performance in future, providing more realistic declarations or initiate appropriate actions for any breach of Connectivity Conditions. Continued default by the generating station entails penalty as may be determined by the Commission.

(5) SGS (excluding CPP) shall provide to SLDC hourly generation summation outputs where no automatically transmitted metering or SCADA/ RTU equipment exists. CPPs shall provide to SLDC 15 minute block wise export/ import MW and MVAR.

(6) The SGS shall provide any other logged readings that SLDC may reasonably require, for monitoring purpose, where SCADA data is not available.
129. **Generator Unit Tripping.**

(1) SGS shall promptly inform SLDC of the tripping of a Generating Unit, with reasons in accordance with *Part IX ‘Operational Event/ Accident Reporting’*. SLDC shall intimate SRLDC about the tripping and their revival. SLDC shall keep a written log of all such tripping, including the reasons with a view to demonstrate the effect on system performance and identifying the need for remedial measures.

(2) SGS shall submit a more detailed report of Generating Unit tripping to SLDC on monthly basis.

130. **Monitoring of Drawal.**

(1) SLDC shall continuously monitor actual MW drawal by Distribution Licensees and other users against their schedules through use of SCADA equipment or direct online monitoring of interface meter readings.

(2) SLDC shall continuously monitor the actual MVAR drawal to the extent possible. This will be used to assist in State Transmission System Voltage management.

(3) For Open Access Customers, appropriate action will be taken by SLDC in case of mismatch beyond permissible limit(s) and keeping in view system security requirements. In case of persistent default or gaming by the Open Access customers, action shall be taken as per Open Access Regulations.

131. **Data Requirement.**

SGS shall submit data to SLDC as listed in Data Registration Part provided in *Appendix C 5*. 
Part XIV -- ENERGY ACCOUNTING

132. Energy Accounting.-
(1) The State Load Despatch Centre shall prepare the Energy Account for the quantity of electricity transmitted through the State Grid, as provided in Section 32(2) (c) of the Act.

(2) SLDC shall prepare every month, the accounts of scheduled and actual energy injection and energy drawal by:-
   a) Distribution Licensees;
   b) Open Access Customers within the State; and
   c) SGS, CPP connected to the State Grid.

(3) The monthly energy accounts so prepared by SLDC shall be sent to all concerned for the purpose of monthly billing.

(4) In the preparation of such energy accounts, SLDC shall take into consideration,-
   a) Agreements for supply and/ or transmission of power, bilateral agreements, short term and spot purchases affected by any licensee, and User;
   b) Policy guidelines or decisions of the State Grid Code Review Committee;
   c) Decisions/ directions of the Commission;
   d) Components of tariff as approved by the Commission; and
   e) Such other accounts by SRPC.

(5) For the purpose of preparation of energy accounts, the joint meter reading(s) taken on 1st of every month at inter connection points between STU/ Transmission licensee and SGS or any IPP or CPP or Open Access Customers and between STU/ Transmission licensee and Distribution Licensees or between two Distribution licensees, shall be conveyed to SLDC by 5th of every month. The DSM energy account shall be prepared by SLDC as per ABT regime, based on CERC (Deviation Settlement Mechanism and related matters) Regulations, 2014/ KSERC DSM Regulations, as amended from time to time.

(6) Monthly State Energy accounts for Kerala shall be prepared by SLDC by 7th of every month and shall be conveyed to all concerned for raising bills. Such energy accounts shall be subject to inspection/ verification/ checking and raising any objection within 15 days of date of issue. If no objection is raised, energy accounts shall be finalized. In case, any objection is raised, same shall be deliberated in Commercial and Metering Committee and finalized as per their decision. Supplementary bills/ credit note shall be raised accordingly.

(7) In case energy accounts prepared/ finalized by SLDC require any change on account of revisions of energy accounts by SRPC, SLDC shall, suo-
moto or on the request of Commercial and Metering Committee, effect changes following the provisions of sub-regulation (5) above.

(8) The beneficiaries shall pay to the respective SGS Capacity charges corresponding to plant availability and/or Energy charges for the scheduled dispatch, in accordance with the relevant contracts/orders of KSERC. The bills for these charges shall be issued by respective SGS to each beneficiary on monthly basis.

(9) The sum of the above two charges from all the beneficiaries shall be fully reimbursed to the SGS for generation according to the given dispatch schedule. In case of a deviation in actual generation from the dispatch schedule, the concerned SGS shall receive or shall pay in accordance with DSM Regulations of CERC/KSERC. Similarly the deviation of actual drawl by any intra-state entity from the net drawl schedule shall be treated as deviation. All 15 minutes block energy figures (net scheduled, actually metered and Deviation) shall be rounded off to the nearest 0.01 MWh. The DSM charges and the modalities of settlement of Deviation shall be in accordance with DSM Regulations of CERC/KSERC.

(10) SLDC shall prepare a detailed procedure for implementation of the mechanism of State Renewable Regulatory Fund, State DSM account and State Reactive Energy Pool account, within three months of notification of this code and submit the same for approval by the Commission.

(11) SLDC shall table the complete statement of the Renewable Energy Fund, State DSM account and the State Reactive Energy pool account annually for audit by the Commission.

133. **SLDC Fees and Charges.**

(1) The SLDC, as per provisions of Section 32 (3) of the Act, may levy SLDC fee and charges as may be determined by the Commission, upon the Generating Companies and Licensees engaged in intra-state transmission of electricity. SLDC fee and charges shall be levied upon Open Access Customers, CPPs and other users, in accordance with the relevant Regulations framed by the Commission.

(2) SLDC shall serve to each utility on 7th of every month the bills of its fees and charges. These charges shall be payable by 13th of every month. Delay in payment of SLDC fee and charges shall be subject to levy of late payment surcharge. Besides this, SLDC may direct disconnection of the utility from the Grid or regulate their supply/despatch and may approach competent authority for levy of fines.
134. **Introduction.**

In order to safeguard the State Transmission System and User’s system from faults occurring in other User’s system, it is essential that certain minimum standards for protection be adopted. This part describes the minimum standards and is supplementary to the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and CEA (Technical Standards for connectivity to the Grid) Regulations, 2007, as amended from time to time.

135. **General Principles.**

(1) Protection standards are treated as interface issues because of the possible severe inter-user boundary repercussions of faults that occur in the system of any entity. Minimum protection requirements are prescribed in this part because inadequate protection or mal-operation of protection system of any entity may result in far reaching consequences, disturbances and even damages to the systems of other entities.

(2) Protection system shall be designed to reliably detect faults on various abnormal conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protected zone.

(3) No item of electrical equipment shall be allowed to remain connected to the State Transmission System unless it is covered by minimum specified protection aimed at reliability, selectivity, speed, stability and sensitivity. Where failure of a protective relay in an entity’s system has substantial impact on the grid, it shall connect an additional protection as redundant or back up protection, besides the main protection, according to the voltage level and importance of the system and equipment connected.

(4) Special protection schemes such as under frequency relay for load shedding, voltage instability, angular instability, generation backing down or islanding schemes may also be required to be provided to avert system disturbance.

(5) All Users shall co-operate to ensure correct and appropriate settings of protection to achieve effective, discriminatory removal of the faulty equipments within the time for target clearance.

(6) The setting of protective relays starting from the generating unit upto the remote end of 66kV/ 33kV and 11kV lines shall be such that only the faulty section is isolated under all circumstances. STU shall notify the initial settings and any subsequent changes to the users from time to time. Protection settings shall not be altered, or protection relays bypassed and/or disconnected without consultation and agreement between all affected Users. In a case where protection is bypassed and/or disconnected by an agreement, then the cause must be rectified and
the protection restored to normal condition as quickly as possible. If agreement has not been reached, the electrical equipment shall be removed from service forthwith.

(7) SLDC shall advise STU regarding:

(i) Planning for upgrading and strengthening protection system based on analysis of grid disturbance and partial/total blackout in the State Transmission System.

(ii) Planning of Islanding and System Split schemes and installation of Under Frequency Relays and df/dt relays.

The Protection Practices and Protocol Manual of SLDC, approved by the State Protection Coordination Committee, shall have provision for the same.

(8) State Protection Coordination Committee (SPCC) shall be constituted as per Regulation 9 of this State Grid Code and shall be responsible for all the protection coordination functions defined under the same. STU shall be responsible for arranging periodical meetings of the Protection Coordination Committee. STU shall investigate any malfunctioning of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection mal-function or issue as discussed and agreed to in the periodical meetings. State Protection Coordination Committee shall decide the date from which the existing protection provided in STU and/or User systems not meeting the minimum requirement as stipulated in this code is required to be changed.

(9) If, it is felt by STU that user’s protection system does not comply with the norms, user is bound to get his protection system checked/tested/inspected by STU and, if required, replaced by new ones after its inspection and testing, so that there is no adverse impact on state grid or STU’s system.

(10) Instead of PLCC system, Optical fibre cable, V-sat or any other Communication system can be used with the approval of SPCC.

136. Fault Clearance Time and Short Circuit Rating.-

(1) From stability consideration, the minimum short circuit current rating and time for switchgear and the maximum fault clearance time for faults on any User’s system directly connected to the State Transmission System, or any faults on the State Transmission System itself, are as follows:

<table>
<thead>
<tr>
<th>Nominal Voltage</th>
<th>Minimum Short Circuit current rating and duration for Switchgear</th>
<th>Target Fault clearance Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>kV</td>
<td>kA (rms) Seconds</td>
<td>milli second</td>
</tr>
<tr>
<td>400</td>
<td>40</td>
<td>1</td>
</tr>
<tr>
<td>220</td>
<td>40</td>
<td>1</td>
</tr>
<tr>
<td>110</td>
<td>40</td>
<td>1</td>
</tr>
<tr>
<td>66</td>
<td>25</td>
<td>1</td>
</tr>
</tbody>
</table>

Fault clearance time less than the above is preferable.
Slower fault clearance time for faults on a User’s system may be agreed to only if, in STU’s opinion, system conditions allow this. STU shall specify the required opening time and short circuit rating of the circuit breakers at various locations for STU/ transmission licensee and Distribution Licensees/ Open Access Customers directly connected to Transmission System. At generating stations, line faults should be cleared at the generating station end within the critical clearing time so that the generators remain in synchronism.

137. Generator Requirements.

All Generating Units and all associated electrical equipment of the Generating Units connected to the State Transmission System shall have adequate protection so that the State Transmission System does not suffer due to any disturbance originating from the Generating units. The generator protection schemes shall cover Differential protection, back up protection, Stator and Rotor Earth fault protection, field failure protection (not applicable to brushless excitation system), negative sequence protection, under frequency, over flux protection, inter-turn Differential protection for generator (optional), restricted earth fault protection for Generator Transformers, pole slipping protection (applicable to units above 200 MW), reverse power protection etc. It should comply with the standards provided in CBIP Manual on Protection of Generators, Generator Transformers and 220 kV and 400 kV Networks(Pub. No 274).


(1) Every EHV line taking off from a Power Station or a substation shall have protection and back up protection as mentioned below:-

a) STU shall notify Users of any changes in its policy on protection.
b) Switchgear equipment and Relay Panels for the protection of lines of STU taking off from a Power Station shall be owned and maintained by the Generator.
c) Any transmission line related relay settings or any change in relay settings will be carried out by the Generator in close co-ordination and consultation with STU.
d) All such issues shall be put up in the next meeting of Protection Coordination Committee for ratification.
e) Carrier cabinets/ equipment, Line matching units including Wave traps and communication cable shall be owned and maintained by STU.
f) All Generators shall provide space, connection facility, and access to STU for such purpose.

(2) 400 kV and 220 kV Transmission Lines,-

a) All 400 kV and 220 kV transmission lines owned by STU shall have two (Main I and Main II) fast acting distance protection schemes.
b) These protection schemes shall be numeric, four independent zones (three forward and one reverse), non-switched (with separate measurement for all phase to phase and phase to ground faults) fast
c) The scheme shall have inbuilt features of power swing blocking, fault recorder, disturbance recorder, event logger, relevant communication ports, single and three phase auto reclosing (with deadline charging and synchro-check facility), Local Breaker Backup (LBB), VT fail and broken conductor alarm/trip and sufficient LEDs to display the faulty phases and zones.

d) Maximum operating time of relay on fault should not exceed 50 ms.

e) Directional earth protection shall be provided in the numerical feeder management relay. Back-up protection, shall also be provided.

f) Additional, two stages over voltage protection is required for 400 kV lines. However, in case of short lines, utility is at discretion to provide this protection.

g) Each transmission line shall have carrier inter-tripping through PLCC equipment for fast clearing of Zone 2 Faults.

(3) 110 kV and 66 kV Lines.-

a) A single distance protection scheme, which shall be numeric, with four independent zones (three forward and one reverse), non-switched (with separate measurement for all phase to phase and phase to ground faults) fast acting distance protection scheme with permissible inter-trip at remote end (in case of Zone 2 fault).

b) The scheme shall have inbuilt features of power swing blocking, fault recorder, disturbance recorder, event logger, relevant communication ports, single and three phase auto reclosing (with deadline charging and synchro check facility), Local Breaker Backup (LBB), VT fail and broken conductor alarm/trip and sufficient LED’s to display the faulty phases and zones.

c) Maximum operating time of relay on fault in zone 1 should not exceed 50 ms.

d) For back up protection, a numerical directional IDMTL over current (for each phase) and earth fault relay shall be provided.

(4) Differential Protection for short transmission lines < 10 KM length.-

The recommendation of SRPC to provide differential protection using fiber optic/any other reliable communication channel between the two ends as one of the main protection and distance protection with reduced zone 1 setting as main two protections, for short 220 kV lines less than 10 KM line may be adopted by STU to have a reliable protection for EHV lines. 110/66 kV lines of length less than 5 KM may be provided with zone 1 delayed distance protection.

(5) Continuity of ground wires,-

Ground wires help to reduce the apparent tower footing resistance. It is
to be noted that all HT/EHV and UHV lines need one or more than one ground wire at a certain height above the conductor to provide the desired shielding.

a) The continuity of such ground wires above the entire length of the transmission lines is necessary to have effective line protection.

b) The tower footing impedance parameters are required to be kept as low as practically feasible and may need special measures like counter poises and other known methods of reducing the footing impedance.

c) Providing Lightning Arrestors in parallel with insulators of towers at suitable locations in lightning prone areas with higher tower footing resistance may also be considered.

139. Transformer Requirements

(1) The protection of EHV Transformers, Power Transformers and Distribution Transformers shall be as per the revised manual on transformers published by the Central Board of Irrigation and Power (CBIP) (Publication No.275). The following minimum protections should be provided for transformers:-

(i) All the 400kV and 220kV class Power transformers shall be provided,

a) With numeric fast acting differential, REF, open delta for tertiary winding (Neutral Displacement Relay) and Over-fluxing relays;

b) In addition, there shall be back up IDMTL over current and earth fault protection;

c) For parallel operation, such back up protection shall have inter-tripping of both HV and LV breakers;

d) LBB protection;

e) For protection against heavy short circuits, the over current relays may incorporate a high set instantaneous element;

f) In addition to electrical protection, transformer own protection viz. buchholz, OLTC oil surge, gas operated relays, winding temperature protection, oil temperature protection, PRV relay shall be provided for alarm and trip functions.

(ii) All the 110 kV, 66 kV and 33 kV class transformers,

a) Of capacity above 5 MVA, the protection shall be the same as mentioned in sub regulation (1) (i) above, except Over fluxing and PRV relays.

b) REF shall also be provided for transformers of capacity equal to or more than 20 MVA.

(iii) All the 66 kV and 33 kV class power transformers of <= 5 MVA capacity, shall be provided on either Transmission or Distribution System;
Over current and earth fault protection with high set instantaneous element along with auxiliary relays for transformer trip and alarm functions as per transformer requirements.

(iv) Small transformers of HT class on the distribution system shall have;
   a) Differential protection shall be provided for capacity 5 MVA and above, along with back up time lag over current and earth fault protection with directional feature for parallel operation.
   b) Transformers of capacity less than 5 MVA shall be protected by time lag over current, earth fault and instantaneous restricted earth fault relays.

(v) In addition to the above Electrical protection all such transformers shall be provided with winding and oil temperature protection and gas operated relays.

140. **Distribution Lines,-**
   (1) All the 33kV and 11kV lines at Connection Points/ Interface points shall be provided with over current and earth fault relays.

   (2) Plain Radial Feeders,-
   Non directional over current and earth fault relays with suitable settings to obtain discrimination between adjacent relay settings shall be provided.

   (3) Parallel/ Ring Feeders,-
   Directional time lag over current and earth fault relay shall be provided.

   (4) Inadvertent Flow,-
   When two systems are operating in parallel with floating tie line, it may not be possible to have tie-line absolutely floating because of dynamics of the network parameters and there will be a flow of energy from one system to another system. Such inadvertent flow shall be accounted for the purpose of commercial billing.

141. **Sub Station Protection,-**
   (1) **Fire Protection,-**
   Adequate precautions shall be taken and protection shall be provided against fire hazards to all Apparatus of the Users, conforming to relevant Indian Standard Specification and provisions in CEA Safety Regulations framed under the Act.

   (2) **Bus Bar Protection,-**
   Numerical protection scheme shall be provided, at all 400 kV, 220 kV substations and generating station switchyards (220 kV and above), for high speed clearance of busbar faults by tripping all circuit breakers connected to the faulty bus. All 220 kV substations except that are radially fed shall be provided with bus bar protection. It should comply with the
requirements/ standards provided in Section 6 of CBIP Manual (Pub. No 274), and the recommendations of SRPC, PCC.

(3) **Local Breaker Backup Protection (LBB).**-
In the event of any circuit breaker failing to trip on receipt of trip command from protective relays, all circuit breakers connected to the bus section to which the faulty circuit breaker is connected are required to be tripped with a time delay of 200 m.sec.

(4) In case of 400 kV system, 'Reactors' are to be used, to limit over voltages due to Capacitive VAR generation in long transmission lines, shall have numeric reactor differential protection, reactor REF protection, back-up protection (over current and earth fault) and other protections to monitor reactor such as bucholz, winding temperature, oil temperature, pressure release valve (PRV), oil level monitors, fire protection etc. It should comply with the requirements in Section 5 of CBIP Manual (Pub. No 274).

(5) All circuit breakers installed in the substations, 11 kV to 110 kV level, should clear the faults in two and half cycles and above 110 kV level in two cycles. The total time of clearing fault including main protection relay shall not exceed that specified at Regulation 135.

(6) Recommendation for providing Auto Reclosing,-
Single phase High speed auto reclosure (HSAR) at 400kV and 220kV lines including the lines emanating from Generating stations with a dead time of 1000 milli second are recommended for adoption. For Intra state feeders both single and three phase reclosing system may be adopted wherever feasible.

(7) Recommended methodology for relay settings for compensated and uncompensated lines, use of system studies to analyze distance relay behavior etc. are presented in Appendix H and I.

(8) General information of the substations, which indicate the details of instrument transformers, availability of protection system, substation protection and monitoring equipments, DC supply, line protection, transformer protection, reactor protection etc. shall be provided annually by the Users to STU/ SLDC for facilitating Protection Audit. Indicative Format is shown in Appendix J.

142. **Calibration and Testing,**-

a) All protection schemes (except distance protection schemes) shall be tested at each 400 kV, 220 kV, 110 kV, 66 kV substation by STU periodically or immediately after any major fault, whichever is earlier.

b) On line annual periodic testing may be adopted for Numerical protection systems.

c) Offline testing shall be conducted for rarely tripped feeders requiring investigation. Distance relay protection schemes and tripping system shall also be tested along with this.
d) Setting, co-ordination, testing and calibration of all protection schemes pertaining to generating units/ stations shall be the responsibility of respective SGS.

e) The overall co-ordination between Generators, Distribution Licensees, transmission licensee and STU shall be decided in Protection Co-ordination Committee meetings.

f) The Protection Co-ordination Committee shall review the testing and calibration procedures as and when needed.

143. Protection System Studies,-

(1) A dedicated group is required to be constituted and trained by STU, Transmission licensee(s) and all Users to carry out computer aided studies for relay settings. It is also recommended that for settings of critical transmission lines and corridors, the relay setting calculations be validated by simulations on the Real Time Digital Simulator (RTDS) available with CPRI and PGCIL.

(2) STU may appoint a reputed Consultant to carry out studies (in which manpower from STU will also involve and get trained) to determine the relay settings for the complete network and also carry out the settings at site in coordination with CTU and STU with time bound target for one time and thereafter the same shall be continued in house by STU.

144. Protection System Management,-

(1) In addition to technical issues related to protection, the management issues related to protection system need to be addressed. A protection management system is existing under the NLDC to monitor and coordinate the protection system of the National Grid and the state grid protection schemes should be in consonance with this. In order to comprehensively address the protection issues in the STS, the STU, transmission licensee and all Users, the following are recommended:-

(i) STU, transmission licensee and all Users shall establish a Protection Application Department with adequate manpower and skill set.

(ii) The protection system skill set is gained through experience in, resolving various practical problems, case studies, close interaction with the relay manufacturers and field engineers.

(iii) Therefore, it is proposed that such people should be nurtured to have a long standing career growth in the Protection Application Department.

(iv) The STU shall constitute a committee containing experts in the field of protection, indicated below for coordination and monitoring of protection functions for the entire grid, duly making the required studies for the protective relay settings:-
a) The Committee shall be headed by a Senior Engineer conversant with the Power system Protection schemes and management, to conduct review meetings periodically, not exceeding 3 months.

b) The Sub Committee may be headed by the respective Senior Engineers of the Protection/ Relay Circles who will conduct review meetings every month and bring the issues to the State Protection Co-ordination Committee for deliberation and decisions.

(2) Relay Setting Calculations,-

(i) The protection group should do periodic relay setting calculations as and when necessitated by system configuration changes. A relay setting approval system should be in place.

(ii) Relay setting calculations also need to be revisited whenever the minor configuration or loading, changes in the system due to operational constraints. Feedback from the field/ substations on the performance of the relay settings should be collected and settings should be reviewed and corrected if required.

(iii) Creating and maintaining data base of relay settings: 
Data regarding settings of relays in their network should be compiled by STU and furnished to the SLDC and a copy should also be submitted to PCC for maintaining the data base.

(3) Co-ordination with System study group, System planning group and other Stakeholders,-

(i) STU, transmission licensee and all Users shall develop a strong system study group with adequate manpower and skill set that can carry out various system studies required for arriving at system related settings in protection system in addition to other studies.

(ii) The Protection Application Department should closely work in coordination with STU, transmission licensee and all Users’ system study group, system planning group and system operation group. Wherever applicable, it should also co-ordinate and work with STU, transmission licensee and all Users to arrive at the proper relay setting calculations for the system as a whole.

(iii) The interface point relay setting calculations at CTU-STU, STU-Distribution, STU-Generators (SGS), CTU-Generators (ISGS) and also generator backup relay setting calculations related to system performance should be periodically reviewed and joint concurrence should be arrived.

(iv) The approved relay settings should be properly documented. Any unresolved issues among the stakeholders should be taken up with the SPCC and resolved.
(4) **Simulation testing for checking Dependability and Security of Protection System for Critical lines and series compensated Lines**,-

a) The protection system for critical lines, all series compensated lines along with interconnected lines should be simulated for intended operation under normal and abnormal system conditions and tested for the dependability and security of Protection system.

b) The RTDS facilities available at CPRI, PGCIL etc. shall be made use of by the STU, transmission licensee and all Users of the Grid for this purpose.

c) The network model should be periodically updated with the system parameters, as and when network changes are incorporated.

(5) **Adoption of Relay Setting and Functional verification of Setting at site,**-

a) The Protection Application Department shall ensure through field testing group that the final relay settings are exactly adopted in the relays at field.

b) There should be clear template for the setting adoption duly authorized and approved by the field testing in-charge.

c) No relay setting in the field shall be changed without proper documentation and approval by the Protection Application Department.

d) The Protection Application Department shall periodically verify the implemented settings at site through an audit process.

e) Protection application department should also maintain a log of all the protection operations. These shall be updated in the Protection asset record and shall be utilized in the up gradation of protection system in future.

(6) **Storage and Management of Relay settings,**-

a) With the application of Numerical relays, increased system size and volume of relay settings; associated data to be handled is enormous.

b) The Entities shall evolve proper storage and management mechanism (version control) for relay settings.

c) Along with the relay setting data, IED configuration file should also be stored and managed.

(7) **Root Cause Analysis of Major Protection Tripping (Multiple Element Outages) along with corrective and Improvement Measures,**-

(i) The routine tripping of transmission lines, transformers and generating units are generally analyzed by the field protection personnel. For every tripping, a trip report along with an associated DR and event logger file shall be generated. However, for major
tripping in the system, the protection application department shall perform the root cause analysis of the event.

(ii) The root cause analysis shall address the cause of a fault, any mal-operation or non-operation of relays, protection scheme etc.

(iii) The root cause analysis shall identify corrective and improvement measures required in the relay setting, protection scheme or any other changes to ensure system security, reliability and dependability of the protection system.

(iv) The Protection Application Department shall keep proper records of corrective and improvement actions taken.

(8) **Performance Indices: Dependability and Security of Protection System,**

The key performance indices should be calculated on yearly basis on the dependability and security of protection system as brought out in CBIP manual.

(9) **Periodic Protection Audit,**

a) Periodic audit of the protection system of each entity shall be ensured by the Protection Application Department of the entity.

b) The audit shall broadly cover the three important aspects of protection system; namely the philosophy, the setting, the healthiness of Fault Clearing System.

c) All the generating companies, STU, transmission licensee and all Users shall co-operate with the SPCC to conduct protection audits and shall attend to the defects/ shortcomings/ observations of such protection audit on the advice of SPCC.

(10) **Regular Training and Certification,**

(i) The members of the Protection Application Department shall undergo regular training to enhance and update their skill sets.

(ii) The training modules shall consist of system studies, relaying applications, testing and commissioning of relays and Certification of protection system.

(11) **Data Requirements,**

Users shall provide STU with data as specified in the Data Registration Part.
145. Introduction.-

(1) This code prescribes the minimum requirements and technical standards of metering for commercial and operational purpose at connection points/ interface points to be provided by Users and STU including, Generating Companies, Distribution Licensees and Open Access Customers and EHV Consumers of Distribution Licensees directly connected to the State Transmission System.

(2) The objective of this code is to prescribe a uniform policy in respect of minimum acceptable standards of metering which shall provide proper metering of the various operating system parameters for the purpose of accounting, commercial billing and settlement of electrical energy and to provide information which shall enable management of the State transmission system in safe, secure and economical manner. Relevant features, parameters, standards and protocols adopted shall be in line with IEGC and CEA Regulations, depending upon the metering applications.

(3) The scope of this code covers the practices that shall be employed and the facilities that shall be provided for the measurement and recording of various parameters like active/ reactive/ apparent power/ energy, power factor, voltage, frequency etc.

(4) This code sets out or refers to the requirements of interface metering and describes type, standards, ownership, location, accuracy class, installation, operation, testing and maintenance, access, sealing, safety, meter reading and recording, meter failure or discrepancies, quality assurance, calibration and periodical testing of meters, additional meters and adoption of new technologies in respect of Interface meters for correct accounting and billing.

(5) This code also lays down the procedure for assessment of Consumption in case of defective and stuck-up meters and lays down guidelines for resolution of disputes between different agencies.

146. Applicability and Standards.-

This Metering Code for Kerala State Grid shall apply to:

(i) STU/ Transmission Licensees;
(ii) Generating Stations (SGSs, IPPs) connected to STS;
(iii) Distribution Licensees connected to State Transmission System;
(iv) EHV Consumers of Distribution Licensee(s) directly connected to State Transmission System;
(v) Open Access Customers availing Open Access through State Transmission system;

(vi) Captive Generators connected to State Transmission System;

(vii) All the equipments installed under these Regulations/ Code shall necessarily conform to the relevant standards/ requirements as specified in the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time.

147. Meter Installation.-

1. Ownership,-
The ownership and responsibility for safety of the metering system shall be as specified in the CEA Metering Regulations.

2. Right to Install Energy Meters,-
Each User shall extend necessary assistance and make available the required space to STU for installation of the metering equipment and provide required outputs of the specified current and voltage transformers to facilitate installation of Meters, RTUs and associated equipment in their premises. Necessary auxiliary supply, if required, shall be extended upto the metering system.

3. Access to Equipment and Data,-
Each User on request shall grant access to install metering equipments and RTUs to STU’s employees, agents/ duly authorized representatives. The STU shall also have access to metering locations for inspecting, testing, calibrating, sealing, replacing the damaged equipments, collecting the data, joint readings of meters and metering equipments and other functions necessary, jointly or otherwise as mutually agreed.

4. Operation and Maintenance of the Metering System,-
The operation and maintenance of the metering system includes proper installation, regular maintenance of the metering system and RTUs, checking of errors of the CTs, VTs and meters, proper laying of cables and protection thereof, cleaning of connections/ joints, checking of voltage drop in the CT/ VT leads, condition of meter box and enclosure, condition of seals, regular/ daily reading of meters and regular data retrieved through CMRI and Basic Computer Software (BCS), attending any breakdown/ fault on the metering system etc. shall be the responsibility of STU.

5. Type of Meters and Metering Capability,-
The Interface meters to be used shall be suitable for measurement of commercial transactions between the utilities according to applicable tariffs. The meters shall be all electronic (static) poly phase tri-vector type having facility to measure active, reactive and apparent energy/ power in all four quadrants i.e. a true import- export meter. All inter user meters
shall be bidirectional while capacitor bank meters and substation auxiliary meters shall be unidirectional, if bidirectional meters already exist, these may not be changed. Any User which connects to the STS shall provide specified meters as above along with the communication facility (redundant, if required). The respective entity/ utility shall also provide local site arrangements such as space, routine access to the meter, power supply, back up/ auxiliary supply and other infrastructure requirements at its cost.

ABT compliant Special energy meters shall be provided at interface points, wherever the energy exchange is based on Availability Based Tariff (ABT), according to Metering Regulations of CEA.

148. Standards for Metering Equipment.-

(1) The STU shall install Special Energy Meters on all inter connection Points for recording of actual net MWh interchanges and MVARh drawals. The installation, operation, maintenance and specification of Special energy meters shall be in accordance with Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time.

(2) All the instrument transformers used in conjunction with the operational metering system shall be of accuracy class 0.2. The existing systems with inferior accuracy class may be continued till the SGCRC decides on the replacement time frame. These shall be of suitable rating to meet the burden of lead wires and meters and shall conform to the relevant IEGC/ CEA/ IS Standards.

149. Testing Arrangement.-

(1) Two types of test facilities shall be available with STU.

a) Automatic meter test bench with high accuracy, static source and 0.02S class electronic reference standard meter (RS Meter) shall be used for testing and calibration of meters.

b) Meter Testing Laboratories duly equipped with test benches and other equipments shall be established at suitable locations for testing and calibration of meters by STU.

c) The Meter Testing benches with 0.02S class reference standard meter shall also be used for checking and calibration of portable testing equipments.

d) Testing, calibration and maintenance of Energy Meters shall conform to the requirements of Indian Standards Specification IS: 9792 and testing equipments shall conform to IS: 12346.

e) Portable test set with static source and electronic reference meter of 0.1S class shall be used for verification and joint testing of accuracy of static tri-vector meters at site on regular/ routine basis.

(2) Separate test terminal blocks for testing of main and check meters shall be provided so that while one meter is under testing, the other meter continues to record actual energy during testing period. Where only one/
main meter exists, an additional meter shall be put in circuit to record energy during the testing period of the main meter so that while the main meter is under testing, the other meter continues to record energy during the period of meter remaining under testing.

(3) Testing at site shall be carried out as follows:-
   a) All meters where power handled is normally more than 10 MW, once in six months;
   b) All meters where power handled is normally less than 10 MW, once in two years.

(4) Subject to Regulations issued by the Commission in this regard, the Licensee shall allow the testing of Open Access Customers’ meters at third party NABL approved Testing Labs in case the Customers so request for the same. In case of testing by third party NABL approved Testing Labs, the Open Access Customers shall apply with prescribed fee to the Licensee.

150. Meter Reading, Data Collection and Data Downloading.-

(1) The STU and the concerned User shall jointly read the meters through their authorized representatives on the 1st of every month at 00.00 hrs/ retrieve meter reading data using CMRI/ Tele metering.

(2) Where a smart meter has been installed for an Open Access Customer connected to the transmission system, the Distribution Licensee shall be required to keep a metering database of the meter readings for the consumer for,-
   a) 13 months in an accessible format;
   b) 5 years in archive.

(3) SLDC shall be responsible for computation of actual net injection/ drawl of the concerned intra state entities, 15 minutes time block wise, based on interface ABT meter readings. The data of the Special energy meters shall be downloaded by the designated representatives of the intra state entities jointly and forwarded to the State Load Dispatch Centre for preparation of intra state energy account of Unscheduled inter changes/ Deviation from schedule of energy and related matters. This data shall be downloaded as per the specified time schedule fixed for issue of intra state DSM account by SLDC.

(4) Provision for remote downloading of data of Special Energy Meters (SEMs) including that of Open Access Customers shall also be made.

151. Right of access to metering data.-

The persons entitled to access metering data from a metering installation shall be,-

(i) The Distribution or Transmission Licensee or STU who is responsible for the metering installation;
(ii) The State Load Despatch Centre;

(iii) The consumer of electricity or the generator of electricity at the metering installation as the case may be;

(iv) Any other person having an agreement to supply electricity to the consumer associated with that metering installation;

In relation to this sub-clause, the person must present a written authorization from the consumer to the Distribution Licensee before the data is to be provided; and

(v) The Commission when such information is required for an investigation.

152. **System for Joint Inspection, Testing, Calibrations.**

(i) (a) The metering system located at metering points between Generating Companies, STU and Distribution Licensees shall be regularly inspected at least once in a year or at an interval lesser than one year as mutually agreed by both the agencies involved for despatch and receipt of energy. Since the static tri-vector meters are calibrated through software at the manufacturers’ works, only accuracy of the meters and functioning shall be verified during joint inspection and certified jointly by both the agencies. After inspection/ testing, the meter shall be properly sealed and a joint report shall be prepared giving details of testing work carried out, details of old seals removed and new seals affixed, test results, further action to be taken, if any etc.

   (b) The agency in whose premises the meter is located shall be responsible for proper security and protection of the metering equipment and sealing arrangement.

   (c) To cover for loss of time, spare meters shall always be kept available with the STU/ owner of the meter/ metering point.

(ii) Joint inspection shall also be carried out as and when difference in meter readings (so corrected) exceeds the sum of maximum error as per accuracy class of main and check meter. The meters provided at the sending end as well as at the receiving end shall be jointly tested/ on all loads and power factor as per relevant standards through static phantom load.

(iii) Calibration, sealing of interface meters, reading for UI Billing purposes before and after installation as and when required shall be carried out by STU or its nominated agency at the expense of the respective User.

(iv) If, it is felt by STU that user’s metering system does not comply with the norms, user is bound to get his metering system checked/ tested/ inspected by STU and if required, replaced by new ones after its inspection and testing.
153. **Sealing.-**

1) Interface meter/ metering systems shall be jointly sealed by the authorized representatives of the concerned agencies as per the procedure agreed upon.

2) Any seal, applied pursuant to this metering code, shall not be broken or removed except in the presence of or with the prior consent of the agency affixing the seal or on whose behalf the seal has been affixed unless it is necessary to do so in circumstances where;
   (a) Both main and check meters are malfunctioning or there occurs a fire or similar hazard and such removal is essential and such consent cannot be obtained immediately;
   (b) Such action is required for the purpose of attending to the meter failure. In such circumstances, verbal consent shall be given immediately and it must be confirmed in writing forthwith.

3) Each agency shall control the issue of its own seals and sealing pliers, and shall keep proper register/ record of all such pliers and the authorized persons to whom these are issued.

4) Sealing of the metering system shall be carried out in such a manner so as not to hamper downloading of the data from the meter using CMRI or a remote meter reading system.

154. **Assessment of consumption of Defective and/ or Stuck-up meter.-**

(1) In case of excessive/ less consumption or stoppage of meter, burning/damage of the meter or damage to the seals, the meter shall be considered as defective. In case, difference in consumption between the main and check meter for any month is more than 0.5%, checking of CT and VT connections and/ or testing of meter at site, using the reference standard meter shall be carried out immediately to determine the accuracy of the main/ check meter.

(2) Whenever a main meter goes defective, the consumption recorded by the check meter/ standby meter shall be referred to. The details of the malfunctioning along with date and time and snap shot parameters along with load survey shall be retrieved from the main meter. The exact nature of the mal-functioning shall be brought out after analyzing the data so retrieved and the consumption/ losses recorded by the main meter shall be assessed accordingly. If main as well as check metering systems become defective, the assessment of energy consumption for the outage period shall be done from the standby meters by the concerned agencies as mutually agreed or at the level of Commercial and Metering Committee.

155. **Replacement of Defective or Stuck-up Meter.-**

Defective or Stuck-up meter shall be replaced as soon as possible. The owner of the meter shall maintain spare inventory of meters in sufficient quantity, so that down time is minimized.

156. **Interface Metering Arrangement.-**

The metering system shall comprise of main, check and standby meters.
The order of precedence for billing shall be Main, Check and Standby.

157. **Location of Interface Meters**.-

(i) **Generating Station, Transmission and Distribution System and ICT** shall be as specified in CEA Metering Regulations (reproduced below):

<table>
<thead>
<tr>
<th>Sl. No.</th>
<th>Entity/ location</th>
<th>Main meter</th>
<th>Check Meter</th>
<th>Standby meter</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Generating Station</td>
<td>On all outgoing feeders</td>
<td>On Outgoing Feeders</td>
<td>(i) High Voltage side of Generator Transformers. (ii) HV side of all Station Auxiliary transformers</td>
</tr>
<tr>
<td>2</td>
<td>Transmission And Distribution System</td>
<td>At one end of the line between the substations of the same licensee, and at both ends of the line between substations of two different licensees. Meters at both ends shall be considered as main meters for respective Licensees.</td>
<td>-</td>
<td>There shall be no Separate standby meter Meter installed at other end of the line in case of two different licensees shall work as Standby meter.</td>
</tr>
<tr>
<td>3</td>
<td>Inter- Connecting Transformer</td>
<td>High Voltage side of Inter-Connecting Transformer</td>
<td>-</td>
<td>Low Voltage side of Inter connecting Transformer</td>
</tr>
</tbody>
</table>

(ii) Operational meters shall also be provided on all outgoing 66 kV, 33 kV and 11 kV feeders as back-up meter for energy audit on feeder and reconciliation of energy with respect to energy measured on LV side of EHV Power Transformer.

(iii) Operational metering shall be sited wherever reasonably required by STU/ Generating Companies for applications other than tariff metering.

(iv) **Open Access Consumers**,- The Inter State Open Access Customers shall provide Special Energy Meters. The embedded Open Access Customers within the State Transmission System shall also provide Special Energy Meters both at the point of injection and point of drawal of supply. Special Energy Meters (SEM) shall be capable of time-differentiated measurement (15 minutes) of active energy and voltage differentiated measurement of reactive energy as specified by STU/ SLDC/ SRLDC. The Distribution licensee may provide Check Meters of the same specification as that of Main Meters.
(v) For real time monitoring of ABT meter parameters in case of open access customers, the ABT meters shall be capable for remote meter data acquisition at base computer centre (SLDC) for which two number independent channels shall be provided by Open Access Customer or licensee (Distribution Licensee) at the cost of OA customer in line with relevant Open Access Regulations.

(vi) **EHV Consumers**,-

In case of EHV Industrial and other consumers directly fed from 220 kV or 110 kV or 66 kV substations, tariff metering shall be provided on outgoing feeder emanating from the EHV substation.

(vii) **Interstate Transmission and Inter Regional Transmission System**, -

Metering arrangement for Inter-State Transmission Lines and for Inter-Regional Transmission System shall be governed by IEGC. Special Energy Meters (SEM) capable of time-differentiated measurement (15 minutes) of active energy and voltage differentiated measurement of reactive energy as specified by CTU/ SRLDC shall be provided on interstate and inter-regional transmission lines. STU shall comply with the requirement for installation, meter reading, downloading and communication of readings of Special Energy Meters (SEM) to SRLDC, as per the operating procedure of SRLDC. STU may install its own Check Meters at inter-state/ inter-regional transmission lines at the periphery of State Transmission System.

(viii) **Substation Auxiliary Consumption Metering**, -

The Auxiliary consumption of substations of STU shall be recorded on LV side of station auxiliary transformers. If such transformer is feeding other local load (colony quarters, street lights etc.) apart from substation auxiliary load, separate metering shall be provided on individual feeders.

(ix) The scheme for location of interface meters shall be submitted to the STU by the owner of the meter in advance before installation of the scheme.

(x) **Metering Arrangements**, -

The above meters shall have following facilities:-

a) Metering equipment shall have external/ internal modem so as to be capable of remote transmission of all data available in the meter memory through any of the information link viz. Radio Frequency, Public Switched Telephone Network (PSTN), Power Line Carrier Communication (PLCC) lines, Microwave, V-SAT Network, Mobile and other means of telemetry like private network of STU or low power radio.

b) The meters shall be self contained and shall normally operate with the power drawn from CT/ VT secondary circuits. However,
meters shall have the provision to display and for downloading the data in case of feeder supply outage.

c) The meter shall be capable of data transmission to RTUs as well as Intelligent Electronic Devices (IED). The format/protocol of communication for data retrieval and data transmission should be made known to the owner of meter by the concerned meter supplier.

158. ABT, Two Part and ToD Tariff Capability.-

(1) The ABT compliant meter shall have provision to compute and store average active and reactive energy and load data with respect to system frequency and the integration of the data. i.e. average kWh and kVARh, and average frequency for 15 minutes time block shall be available in each meter in CT/VT secondary quantities.

(2) Meters shall also have ‘reactive high and reactive low’ volt-ampere hour registers for total drawal, high and low system voltage drawal. The Distribution Licensee wise summation of kWh, kW, pf, demand, Scheduled interchange/ unscheduled interchange/ deviation will be done at the main computer station provided at central billing station or at State Load Despatch Centre.

(3) The metering arrangement for recording Distribution Licensee consumption/ power input in his area of supply shall consist of the following:

(i) Frequency based ABT compliant meters shall be provided on 66 kV or lower voltage lines feeding each Distribution Licensee area of supply. The function of these meters will be as under,-

a) To measure Distribution Licensee-wise UI (Unscheduled Interchange)/ Deviation from schedule energy and corresponding average frequency during 15 minutes time block;

b) The Distribution Licensee wise summation of kWh, kW, pf, demand, scheduled interchange/ unscheduled interchange/ deviation, will be done at the main computer station provided at central billing station or at State Load Despatch Centre;

c) For this purpose, the various parameters shall be integrated at one centrally located station preferably at State Load Despatch Centre at Kalamassery through suitable computer hardware and software system.

d) The STU shall install and make operative an operational Meter Data Collection system under SCADA for storage, display and processing of operational metering data. All users shall make available outputs of their respective operational meters to the SCADA interface.

(ii) Static Trivector meters are to be provided on LV secondary side of all EHV transformers. The function/ duty of this meter will be as under,-

a) Measurement of kWh energy supplied to Distribution Licensee for billing purpose.

b) 15 minute block wise as well monthly kW/ kVA demand and power factor, caused by Distribution Licensee on each EHV transformer.
159. **Technical Specifications/ General Guidelines of Interface Energy Meters under SAMAST.**

(1) The energy metering system specified herein shall be used for tariff metering for bulk, inter-utility power flows, in the State. One static type composite meter shall be installed for each EHV circuit, as a self-contained device for measurement of active energy (MWh) transmittals in each successive 5 minutes time block and certain other functions, as described in the following clauses,-
   a) All meters shall be DLMS compliant for Interface Energy Meter (IEM) communication protocol;
   b) It must also be compliant for Indian Companion COSEM standard;
   c) Three layers of Data security shall be ensured as per IEC-62056-51 standard;
   d) Detection of Tamper conditions as included in IEC 62056 standards must be mandatory for DLMS compliant meter protocol;
   e) Meter shall comply with IS 16444 for all its requirements.

(2) The meters shall be suitable for Advanced Metering Infrastructure (AMI) with bidirectional communication. The meter shall communicate with Data Connector Unit (DCU)/ Access Point/ Head End System (HES) on any one of the communication technologies mentioned in IS 16444.

(3) The meter shall have a feature of upgrading the latest firmware remotely.

(4) The meters shall be suitable for being connected directly to voltage transformers (VTs) having a rated secondary line-to-line voltage of 110V, and to current transformers (CTs) having a rated secondary current of **1A (Model-A)** or **5A (Model-B)**. Any further transformers/ transactions/ transducers required for their functioning shall be in-built in the meters. Necessary isolation and/ or suppression shall also be built-in, for protecting the meters from surges and voltage spikes that occur in the VT and CT circuits of extra high voltage switchyards. The reference frequency shall be 50 Hz.

(5) The active energy (Wh) measurement shall be carried out on 3-phase, 4-wire principle, with an accuracy as per class 0.2S of IEC-62053-22:2003. In Model-A (for CT secondary rating 1A), the energy shall be computed directly in CT and VT secondary quantities, and indicated in watt-hours. The meter shall compute the net active energy (Wh) sent out from the substation bus bars during each successive 5-minutes block, and store it in its memory up to second decimal with plus sign if there is net Wh export and with a minus sign if there is net Wh import. It shall also display on demand the net Wh sent out during the previous 5-minute block.
(6) The meter shall continuously integrate and display on demand the net cumulative active energy sent out from the substation bus bars up to that time. The cumulative Wh reading at each midnight shall be stored in the meter’s memory. The register shall move backwards when active power flows back to substation bus bars.

(7) The meter shall count the number of cycles in VT output during each successive 5-minutes block, and divide the same by 300 to arrive at the average frequency. This shall be stored in the meter’s memory in Hertz up to second decimal. The average frequency of the previous 5-minutes block shall also be displayed, on demand in Hertz.

(8) The meter shall continuously compute the average of the \( \text{rms} \) (root mean square) values of the three line to neutral VT secondary voltages as a percentage of 63.51 V, and display the same on demand. The accuracy of the voltage measurement/computation shall be at least 0.5\%, a better accuracy such as 0.2\% in the 95-105\% range being desirable.

(9) The Reactive energy (\( \text{VARh} \)) measurement shall be carried out on 3-phase, 4-wire principle, with an accuracy as specified in clause 11.0 of IEC 62053-23: 2003. In model-A (for CT secondary rating 1A), the energy shall be computed directly in CT and VT secondary quantities, and indicated in watt-hours. The meter shall compute the net Reactive energy (\( \text{VARh} \)) sent out from the substation bus bars during each successive 5-minutes block, and store it in its memory up to second decimal with plus sign if there is net \( \text{VARh} \) export and with a minus sign if there is net \( \text{VARh} \) import. It shall also display on demand the net \( \text{VARh} \) sent out during the previous 5-minute block.

(10) The meter shall also compute the reactive power (\( \text{VAR} \)) on 3-phase, 4-wire principle, with an accuracy as specified in clause 11.0 of IEC 62053-23: 2003 and integrate the reactive energy (\( \text{VARh} \)) algebraically into two separate registers, one for the period for which the average \( \text{rms} \) voltage is 103.0\% or higher, and the other for the period for which the average \( \text{rms} \) voltage is below 97.0\%. The current reactive power (\( \text{VAR} \)), with a minus sign if negative, and cumulative reactive energy (\( \text{VARh} \)) readings of the two registers shall be displayed on demand. The readings of the two registers at each midnight shall also be stored in the meter’s memory. In Model-A (for CT secondary rating of 1 A), the reactive power and reactive energy transmittals shall be computed in \( \text{VAR/VARh} \) directly calculated in CT and VT secondary quantities. When lagging reactive power is being sent out from substation bus bars, \( \text{VAR} \) display shall have a plus sign or no sign and \( \text{VARh} \) registers shall move forward. When reactive power flow is in the reverse direction, \( \text{VAR} \)
display shall have negative sign and VARh registers shall move backwards.

(11) In the Model-B (for CT secondary rating of 5A), all computations, displays and memory storage shall be similar except that all figures shall be one fifth of the actual Wh, VAR and VARh worked out from CT and VT secondary quantities.

(12) The meters shall fully comply with all stipulations in IEC standards 62052-11: 2003 and 62053-22: 2003, except those specifically modified by this specification. The reference ambient temperature shall be 30⁰C.

(13) Errors shall be reasonable for all power factor angles from 0 to 360.

(14) For reactive power (VAR) and reactive energy (VARh) measurements, IEC 62053-23: 2003 shall be complied with. The accuracy of measurement of reactive energy shall be as per Class 2.

(15) Each meter shall have a test output device (visual) for checking the accuracy of active energy (Wh) measurement. The preferred pulsing rate is twenty (20) per Wh for Model-A and four (4) per Wh for Model –B. It shall be possible to couple this device to suitable testing equipment also.

(16) No rounding off to the next higher last decimal shall be done for voltage and frequency displays. All 5 minute Wh figures shall however be rounded off to the nearest last decimal.

(17) The three line-to-neutral voltage shall be continuously monitored and in case any of these falls below about 70%, a normally flashing lamp provided on meter’s front shall become steady. It shall go off if all three voltages fall below 70%. The time blocks in which such a voltage failure occurs/ persists shall also be recorded in the meter’s memory with a symbol "**". If 3 Phase rms voltage applied to the IEM is in between 5% to 70% of rated voltage, IEM should record low voltage symbol "L" in place of star(*) and if voltage is less than 5% of rated voltage, IEM meter should record Zero voltage symbol "Z". The lamp shall automatically resume flashing when all VT secondary voltages are healthy again. The two VARh registers specified in clause 7 above shall remain stay-put while VT supply is unhealthy. When Bay feeder is out, facility should be provided to download data on backup system (battery) independently and see on display on off line mode.

(18) The meters shall normally operate with the power drawn from the VT secondary circuits. The total burden imposed by a meter for measurement and operation shall not exceed 10VA on any of the phases. An automatic backup for continued operation of the meter’s calendar-clock, and for retaining all the data stored in its memory, shall be provided through a long-life battery, which shall be capable of supplying the required power for at least 2 years. The meters shall be
supplied duly fitted with the batteries, which shall not require to be
changed for at least 10 years, as long as total VT supply interruption
does not exceed two years. The battery mounting shall be designed to
facilitate easy battery replacement without affecting Printed Circuit
Board (PCB) of the meter. The meters shall not require any separate
auxiliary supply for their operation. All displays may disappear on loss of
VT supply.

(19) Each meter shall have a built-in calendar and clock, having an accuracy
of 10 seconds per month or better. The calendar and clock shall be
correctly set at the manufacturer’s works. The date (year-month-day) and
time (hour-min.-sec.) shall be displayed on the meter front (when VT
supply has been connected), on demand. Meter shall have the
intelligence to synchronize the time with GPS signal and can be possible
through a single click from the software itself while connecting the meter
with PC. Limited time synchronization through RS 485 port shall be
possible at site. When an advance or retard command is given, twelve
subsequent time blocks shall be contracted or elongated by five seconds
each. All clock corrections shall be registered in the meter’s memory and
suitably shown on print out of collected data. Standard for time
synchronization shall be as per IS16444/ IS15884 Standards.

(20) Each meter shall have a unique identification code, which shall be
marked permanently on its front, as well as in its memory. All meters
supplied to as per this specification shall have their identification code
starting with “IM”, which shall not be used for any other supplies. “IM”
shall be followed by a dash and an eight digit running serial number,
further followed by a dash and “A” for Model-A and “B” for Model-B, for
the use with CT secondary of 1 A and 5 A respectively.

(21) Each meter shall have at least one eleven (11) character, seven-
segment electronic display, for indication of the following (one at a time),
on demand:-

i) Processor’s identification code and model: EM12345678A

ii) Date (year month day)  : 20180311 d

iii) Time (hour min. sec.)  : 195527 t

iv) Cumulative Wh reading:  12345678.6 C

v) Average frequency of the previous block:  49.89 F

vi) Net Wh transmittal during the previous block: - 28.75 E

vii) Net VARh transmittal during the previous block: - 18.75 R
viii) Average % voltage: 99.2 U
ix) Reactive power (VAR): 106.5 r
x) Voltage - high VARh register reading: 01234567.5 H
xi) Voltage - low VARh register reading: 00123456.4 L
xii) Low battery indication

(22) A gold plated touch key or push button shall be provided on the meter front for switching on the display and for changing from one indication to the next. (The display shall switch off automatically about one minute after the last operation of touch key/push button). When the display is switched on, the parameter last displayed shall be displayed again, duly updated.

(23) Each meter shall have a non-volatile memory in which the following shall be automatically stored:

i) Average frequency for each successive 5-minute block, in Hertz upto second decimals.
ii) Net Wh transmittal during each successive 5-minute block, upto second decimal, with plus sign if there is net Wh export and with a minus sign if there is net Wh import.
iii) Net VARh transmittal during each successive 5-minute block, upto second decimal, with plus sign if there is net VARh export and with a minus sign if there is net MVARh import.
iv) Cumulative Wh transmittal at each midnight, in eight digits including one decimal.
v) Cumulative VARh transmittal for voltage high condition, at each midnight, in eight digits including one decimal.
vi) Cumulative VARh transmittal for voltage low condition, at each midnight, in eight digits including one decimal.
vii) Date and time blocks of failure of VT supply on any phase, as a star (*) / (L) / (Z) mark.

(24) The meters shall store all the above listed data in their memories for a period of fifteen (15) days. The data older than fifteen (15) days shall get erased automatically.

i) Each meter shall have an optical port on its front for tapping all data stored in its memory using Laptop along with required optical to USB converter. In addition to the above each meter shall also be provided with a RS 485 as well as LAN port for RJ 45 connection on
one of its sides, from where all the data stored in the meter's memory can also be tapped into the local computer directly. The overall intention is to tap the data stored in the meter's memories once a week from any of the above mentioned ports and transmit the same to a remote central computer using AMR (Automatic Meter Reading) system or other means of communication, through the local PC.

ii) All meters should be compatible with Optical port, RS 485 port and LAN port all together at a time and communicate independently. It shall also be possible to obtain a print out (hard copy) of all data collected from the meters, using the local PC. Data collection from any local laptop/PC should be possible by installing data collection software.

iii) All meters shall have internal chargeable battery to power-up the meters during the shutdown condition of the element and adapter to be provided at each station where meters are installed to charge-up as and when required. Internal battery can be replaced using the spare provided by suppliers.

iv) Meter protocol shall be such that slave ID of the meter can be accessed remotely from control centre in case of meter replacement without any manual intervention in AMR system.

(25) The whole system shall be such as to provide a print out (both from the local PC, and from remote central computer) of the following form:

```
 20 49.82  +16.28  +12.63  49.63  +15.95  +10.55
IEM-12345678-A 12345678.6  01234567.5  00123456.4  16-06-2018
 00 49.99  +14.72  -16.25  50.20  +13.83  -12.63
```

The above data shall be available in text file format (file extension as per IEEE standard) exportable to Excel. This data shall also be available in second text file format (file extension as per IEEE standard) exportable to Excel. The user shall have the option to download one or both text files. Format to be approved during technical demonstration. Indication of time retard or advance to be provided without disturbing the proposed format.

(26) The meters shall be supplied housed in compact and sturdy, metallic or molded cases of non-rusting construction and/or finish. The cases shall be designed for simple mounting on a plane, vertical surface such
as a control/relay panel front. All terminals for CT and VT connections shall be arranged in a row along the meter’s lower side. Terminals shall have a suitable construction with barriers and cover, to provide a secure and safe connection of CTs and VTs leads through stranded copper conductors of 2.5 sq. mm size.

(27) All meters of the same model shall be totally identical in all respects except for their unique identification codes. They shall also be totally sealed and tamper proof, with no possibility of any adjustment at site, except for clock correction.

(28) The meters shall safely withstand the usual fluctuations arising during faults etc. In particular, VT secondary voltages -115% of rated applied continuously and 190% of rated applied for 3.0 seconds, and CT secondary current -150% of rated applied continuously and 30 times of rated applied for 0.5 seconds, shall not cause any damage to or mal operation of the meters.

(29) The meters shall also withstand without any damage or mal operation reasonable mechanical shocks, earthquake forces, ambient temperature variations, relative humidity etc. They shall have an IP 51 category dust-tight construction, and shall be capable of satisfactory operation in an indoor, non-air conditioned installation.

(30) The meters shall continue to function for the remaining healthy phase(s), in case one or two phases of VT supply fails. In case of complete VT supply failure, the computation of average frequency (as per clause 5 above) shall be done only for the period during which the VT supply was available in the 5-minute block. Any time block contraction or elongation for clock correction shall also be duly accounted for.

(31) The harmonics shall preferably be filtered out while measuring Wh, VAR and VARh, and only fundamental frequency quantities shall be measured/computed.

(32) Either the meters shall have built-in facility (e.g. test links in their terminals) for in-situ testing, or a separate test block shall be provided for each meter.

(33) The Contractor shall provide the necessary software which would enable a local IBM- Compatible PC to:

i) Accept the data from the RS 485 port and store it in its memory in binary read only format in an user-defined file name (file name format must be ‘ddmmyysubstation name-utility name’);

ii) Polling feature along with a task scheduler to run the data downloading software at a pre-designated date and time repeatedly or by manually selecting a meter. File naming for such downloaded
data should also be in user-defined format. A detailed activity log shall also be available for each downloading operation;

iii) Upload/import meter data (binary files) in the software for further processing. While uploading, there shall be provision to upload all selected files with single key-stroke;

iv) Convert the binary file(s) to text file(s). There should be provision to select multiple files based on filename, convert all selected files with single key-stroke and store the text files in the same location where binary files are stored;

v) Display the collected data on PC’s screen in text format, with forward/backward rolling;

vi) Print out in text format the data collected from one or more meters, starting from a certain date and time, as per operator’s instructions;

vii) Transmit the collected data, in binary format, through an appropriate communication link to the central computer, starting from a certain date and time, as per operator’s instructions; and

viii) Store the collected data in binary format, on a CD/Pen Device. In addition to above, in general the software should be able to convert DLMS/COSEM compliant IEM’s data to existing format as well as in tabular (.csv) format as applicable.

(34) The above software shall further ensure that absolutely no tampering (except total erasures) of the collected metering data is possible during its handling by the PC. The software shall be suitable for the commonly available PCs, and shall be supplied to Owner in a compatible form to enable its easy loading into the PCs available (or to be installed by the Owner/others) at various substations.

(35) Quality Assurance.-

The quality control procedure to be adopted during manufacture of the specified equipment shall be mutually discussed and finalized in due course, generally based on the established and proven practices of the manufacturer. The software should be user friendly and can be easily installed in any PC/Laptop irrespective of operating system of the PC/Laptop and also shall be certified for ensuring data handling capabilities. The same should be demonstrated by party during technical evaluation only. During demonstration standard meter is to be brought by party. Therefore software shall be offered for technical compatibility, which will
be evaluated technically, before taking up further necessary action in the procurement process.

(36) **Testing.-**

All equipments, after final assembly and before dispatch from manufacturer’s works, shall be duly tested to verify that it is suitable for supply to the Owner. In particular, each and every meter shall be subjected to the following acceptance tests:-

i) Verification of compliance with Table 4 under clause 8.1 of IEC-62053-22: 2003, in both directions of power flow, for class 0.2S;

ii) Test of the register ratio and the impulse value of the transmitting device, for both directions;

iii) Verification that VARh measurement errors are within values permitted for class 2 in Table 6 of IEC 62053-23 for both directions of power flow;

iv) Effect of ±10% variation in measuring circuit voltage, on accuracy of Wh and VARh measurement;

v) Power loss;

vi) Dielectric properties;

vii) Starting and running with no-load for Wh and VARh, in both directions;

viii) Functional checks for display and memory;

ix) Accuracy of the calendar and clock;

x) Accuracy of voltage and frequency measurement.

(37) Any meter which fails to fully comply with the specification requirements shall be liable to be rejected by the Owner. However, the Owner may purchase such meters at a reduced price in case of marginal non-compliance, at his sole discretion.

(38) Acceptance Tests for PC Software and data down loading using RS 485 port.-

All IEMs after final assembly and before despatch from Contractor’s/Manufacturer’s works shall be duly tested to verify that they are suitable for downloading data using Optical port and RS 485 port and shall be subjected to the following acceptance tests:

i) Downloading Meter Data from the Meter(s) to PC;

ii) Compatibility with PC Software;

ii) Functioning of advance and retard time commands;

iv) Per meter downloading time verification.
(39) **Type Tests,-**

One (1) out of every hundred (100) meters shall be subjected to the complete range of type tests as per IEC-62053-22: 2003, IEC-62053-23: 2003 and IEC 62052-11: 2003, after final assembly. In case of any failure to pass all specified tests, the contractor shall arrange to carry out the requisite modifications/ replacements in the entire lot of meters at his own cost. After any such modifications and final assembly, two (2) meters selected out of the lot by the Owner’s representative shall be subjected to the full range of type tests. The lot shall be accepted by the Owner only after successful type testing.

(40) The meters used for type testing shall be separately identified, duly marked, and supplied to the Owner in case they are fully functional and as good as other (new) meters, after necessary touching up/ refurbishing. In case this is not possible, the contractor shall provide their replacements at no extra cost to Owner.

(41) The Contractor shall arrange all type testing specified above, and bear all expenses for the same.

(42) **Installation and Commissioning,-**

i) The static energy meters specified above shall be installed at various EHV substations owned by the Owner, DISCOMs and other agencies. The exact location and time-table for installation shall be finalized by the Owner in due course, and advised to the contractor, such that contractor’s responsibility in this respect ends within six (6) months of completion of all supplies.

ii) The Contractor shall be responsible for total installation and commissioning of the meters (along with test blocks, if supplied separately) as per Owner’s advice, including unpacking and inspection on receipt at site, mounting the meters on existing control and relay panels at an appropriate viewing height, connection of CT and VT circuits including any required rewiring, functional testing, commissioning and handing over. The Contractor’s personnel shall procure/ carry the necessary tools, equipment, materials and consumables (including insulated wires, lugs, ferrules, hardware etc.).

iii) As part of commissioning of Data Collecting Devices (DCDs) the Contractor shall load the software specified in sub-regulations (33) and (34) above into the PCs at the respective substations, and fully
commission the total meter reading scheme. He shall also impart the necessary instructions to substation engineers.

(43) The following technical information shall be furnished by the Bidders in their offers:-
   i) Foreseen dimensions of proposed meter;
   ii) Expected weight of proposed meter;
   iii) Dimensions and weight of the test block, if supplied separately.

(44) Warranty,-
   i) The Meter shall be provided with warranty of 60 months/ 5 years from the date of commissioning.
   ii) The warranty would include repair, replacement, part material replacement cost and one way (return) transportation cost (including insurance of transit).
   iii) Meter software, if upgraded by OEM should be supplied free of cost with initiation taken from party. Remote service person name to be indicated during bidding.
   iv) Meters which are found defective/ inoperative at the time of installation or become inoperative/ defective within the warranty period, shall be replaced within one month of receipt of report for such defective/ inoperative meters.

(45) For RS 485 Compatibility (plus, minus, common terminals to be provided for easy termination of daisy chain/ similar connection or direct connection to PC by a cable) should be provided separately to collect data from meter independently by PC/ Laptop. Any additional cable (with optical adapter or converter) or software as required for data downloading from Special energy meters to laptop are to be supplied.

(46) Meters should be supplied with latest/ compatible software (should be compatible with old and new meter’s data download and handling). Any new software as required to be installed within the warranty period are to be done by the party or through remote support to the client.

(47) The total arrangement shall be such that one (1) operation (click on “data down load from meter” button on software) can carry out the whole operation in about five (5) minutes per meter or preferably faster.

(48) The layout of software front end/ user interface has to be approved by bidder during technical evaluation/ demonstration. However a standard template sheet will be provided along with bid for reference.

(49) Software for Windows/ Office/ Antivirus is to be supplied. Antivirus software should not slow down processes and same have to be demonstrated during technical demonstration.
Above specification is only the minimum. Any higher standard required for the purpose intended (meter data handling) would be assessed by vendor and should be supplied accordingly. The Decision Review System (DRS) should be approved during the drawing approval stage.

Source Code Control (SCC),-

1) Meter should be accommodatable in existing C&R panel of standard size (Alstom/ ER/ ABB/ Siemens) in kiosk or C&R panel with door closed.

2) Step by Step procedure (on screen shot type or desktop video capture) and software to be supplied during the time of commissioning for:
   a) Installation/ Re-installation of Database handling software into Laptop/ PC;
   b) Meter maintenance/ site-testing procedure as per relevant IS/ IEC standards;
   c) Procedure for data downloading from Meter by Laptop/ Desktop PC.

3) The Meters are to be used as Interface energy meters in transmission system of STU (State Transmission Utility). As on the date of delivery, the supplied meters shall comply with all the statutory Regulations as required under KSERC/ CERC/ CEA/ IEGC as applicable and the same should be declared by the supplier during delivery along with warranty certificate.
CHAPTER VII
COMMUNICATION AND DATA REGISTRATION CODE

Part XVII – COMMUNICATION SYSTEM

160. Introduction.-
(1) This part specifies the minimum requirements of Communication system, as per the CEA Technical Standards for Communication System in Power Sector, to be provided by Users at Connection points/ Interface points and Cross Boundary Circuits, to enable SLDC/ STU/ CTU to manage the Transmission system in safe, secure and economic manner.

(2) The objectives of this part are:
   a) to ensure seamless integration, reliable, redundant and secure communication;
   b) to ensure that any network change shall not cause any adverse effect on functioning of existing Communication System and the System shall continue to perform intended function with specified reliability, security and quality;
   c) A Data Provider or an intervening communication system provider is required to be aware, in advance, of the standards and conditions his system has to meet for being connected into the existing Communication System;
   d) All Users, SLDC, STU, Power Exchanges, Communication Service Providers etc. whose electrical system is connected to the Transmission system, Market Operation Service Providers and other Service Providers like Forecast, Weather and Ancillary services, shall abide by the principles and procedures as applicable to them in accordance with these Regulations.

161. Nodal Agency.-
(1) The Central Transmission Utility shall be the nodal agency for planning and coordination for development of Communication system for interstate transmission system user.

(2) The State Transmission Utility shall be the nodal agency for planning and coordination for development of Communication system for intra - State transmission system user.

(3) The SLDC shall be the nodal agency for ensuring integration of the Communication system at regional level with SCADA, WAMS, Video Conferencing Systems (VCS), Automatic Meter Reading (AMR), EPABX, Tele-protection system etc. shall be SRLDC for ISGS, ISTS and SLDC; and for State Generating Stations, distribution companies, Intra-State entities, intra State transmission system etc.
162. Role and responsibilities of various Organizations/ Entities.-

(1) **Role of Central Electricity Authority (CEA).**

CEA shall,-

(i) formulate communication planning criterion and guidelines for development of reliable communication system for the power system infrastructure of India duly considering requisite route redundancy, capacity, as well as requirements of smart grid and cyber security.

(ii) formulate and notify technical standards, cyber security requirements in accordance with the Cyber security Policy of the Government of India from time to time and the protocol for the communication system for Power Sector in the country.

(iii) prepare perspective plan for communication duly considering optimal utilization of transmission assets for communication purposes having regards to the transmission planning carried out by CEA through Standing Committee on Power System Planning;

(iv) carry out periodic review of the perspective plan;

(v) monitor and facilitate timely completion of schemes and projects for improving and augmenting the associated communication system along with transmission system in the power sector.

(2) **Role of CTU.**

The Central Transmission Utility shall,-

(i) in due consideration of the planning criteria and guidelines formulated by CEA, be responsible for planning and coordination for development of reliable National Communication System backbone among National Load despatch Centre, Regional Load Despatch Centre(s) and State Load Despatch Centre(s) along with Central Generating Stations, ISTS Substations, UMPPs, inter-State generating stations, IPPs, renewable energy sources connected to the ISTS, Intra State entities, STU, State distribution companies, Centralized Coordination or Control Centers for generation and transmission. While carrying out planning process from time to time, CTU shall in addition to the data collected from and in consultation with the users consider operational feedback from NLDC, RLDCs and SLDC;

(ii) plan the communication system comprehensively and prospectively for users considering the requirement of the expected nodes in consultation with Standing Committee constituted by CEA;

(iii) plan communication system for the cross border Transmission system for cross border exchange of power;
(iv) integrate communication planning with transmission and generation project planning in a comprehensive manner;
(v) discharge the above function in consultation with the CEA, State Transmission Utilities, ISGS, Regional Power Committees, NLDC, RLDCs and SLDC;
(vi) provide access to its communication node to interface the wideband network being implemented by State Transmission Utilities to have a single interconnected network and shall coordinate with State Utility for the interface requirement;
(vii) be the Nodal Agency for supervision of communication system in respect of inter-State communication system and will implement centralized supervision for quick fault detection and restoration;
(viii) carry out the integrated planning for development of backbone communication systems providing interfaces to wideband communication network of STUs at interface nodes in consultation with STUs;
(ix) provide access to its wideband network for grid management and asset management to all the users;
(x) extend the required support to Control Centers for Integration of communication system at respective ends.

(3) **Role of SRLDC,**

The Southern Regional Load Despatch Centre (SRLDC) shall,-

(i) be the nodal agency for integration and supervision of Communication System of the ISTS, ISGS, SLDCs and IPPs at SRLDC end for monitoring, supervision and control of Power System and adequate data availability in real time;
(ii) collect and furnish data related to Communication System of various users, CTU, SRLDC, STU and SLDC to SRPC;
(iii) provide operational feedback to CTU.

(4) **Role of SLDC,**

The State Load Despatch Centre shall,-

(i) be the nodal agency for integration of Communication System in the intra-State network, distribution system and generating stations at SLDC end for monitoring, supervision and control of Power System and adequate data availability in real time;
(ii) shall provide operational feedback to CTU and STU.

(5) **Role of STU,**

The STU shall,-

(i) be responsible for planning, coordination and development of reliable communication system within the State including appropriate protection
path among State Load Despatch Centre, Backup LDC and Distribution Licensee Control Centers, including Main and Backup as applicable along with STU Substations, intra-State Generating Stations;

(ii) plan redundant communication system upto the nearest Inter State Transmission System wideband communication node for integration with the inter State communication system at appropriate nodes;

(iii) discharge all functions of planning related to the State backbone communication system in consultation with Central Transmission Utility, State Government, generating companies and distribution companies in the State;

(iv) provide access to its wideband Network for grid management by all the users;

(v) extend the required support to Control Centers for integration of communication system at respective ends.

(6) **Role of Users,**

(i) The Users including renewable energy generators shall be responsible for provision of compatible equipment along with appropriate interface for uninterrupted communication with the concerned control centres and shall be responsible for successful integration with the Communication system provided by CTU or STU for data communication as per the guidelines issued by NLDC/ SLDC.

(ii) The Users may utilize the available transmission infrastructure for establishing Communication upto the nearest wideband node for meeting communication requirements from their stations to the concerned control centers.

(iii) The Users shall be responsible for expansion/ upgradation of their Communication equipments as per the direction of SLDC/ NLDC.

(iv) The Users are also responsible for the operation and maintenance of the Communication equipments owned by them.

(7) **The Role of NPC, RPC and NLDC** shall be as provided in the CERC (Communication System for Inter State Transmission of Electricity) Regulations.

163. **Boundary of the Communication System,**

(1) **ISTS Communication system,**

(i) NLDC;

(ii) RLDCs;

(iii) SLDC (ISTS interconnection);

(iv) ISTS substations of transmission licensee;

(v) ISGS, Central Generating Stations, Solar generation plants/ Solar Parks and Wind generation pooling stations connected to ISTS.
(2) **Intra State Communication System,-**

(i) SLDC (State Inter-connection);
(ii) STU;
(iii) Distribution Companies;
(iv) State Generating Stations including renewable generators and IPPs connected to the State network;
(v) Substations of STU and State Transmission licensees.

164. **Periodic Testing of the Communication System.-**

(1) All users that have provided the Communication systems shall facilitate for periodic testing of the Communication system in accordance with the procedure for maintenance and testing prepared by CTU/STU.

(2) Testing process for Communication network security should also be included even for third party system, if exists, in accordance with the procedure for maintenance and testing prepared by CTU/STU.

**Technical Standards for Communication System**

165. **Functional Requirement.-**

(1) The primary function of the Communication network is to provide a highly secured and reliable, voice (express voice and administrative voice circuits) and data (low and high speed data) communication system in support of the WAM (Wide Area Monitoring) System, SCADA/EMS system, Protection System, Market Operation Service and Service Providers (Forecast, Weather and Ancillary services) with necessary interfaces.

(2) The Communication system shall finally form a wideband backbone on all India basis to support the requirement of the Power System Operation and Market operation.

166. **Standards and Codes of Practice.-**

(1) The Communication service providers shall follow the industry best practices and applicable industry standards in respect of the equipment installation and its operation and maintenance.

(2) The Communication equipments shall comply with the latest version of the relevant Fiber Optic Association (FOA) Standards, BIS (Bureau of Indian Standards), British Standard (BS), or International Electro-Technical Commission (IEC) Standard or American National Standards Institute (ANSI) or any other equivalent International Standard, ITU-T (International Telecommunication Union - Telecommunication)/CCITT (Consultative Committee for International Telephony and Telegraphy), CISPR (International Special committee on Radio Interference);
Provided that whenever an International Standard or International Electro-
Technical Commission Standard is followed, necessary corrections or
modifications shall be made for prevailing local ambient conditions before
adoption of the said Standard.

(3) The effect of wind, storms, flood, lightening, elevation, temperature
extremes, icing, contamination, pollution, earthquakes etc. shall be
considered in the design and operation of the connected facilities.

(4) The Standards, General/ Functional/ Technical Requirements and the
Codes of Practice to be followed for interfacing to the Communication
System, Wideband Communication (Fibre Optic/ Fibre Optic Cable/
Wideband Network), PLCC, Radio (GPRS), VSAT etc. shall be as per the
Standards provided in CEA ‘Technical Standards for Communication
System in Power Sector’.

167. **Access Policy.**

(1) Data and Information is a valuable asset for the Indian Power System
where strict confidentiality shall be maintained. Protecting information
assets from unauthorized, incorrect or accidental access, use,
modification, destruction or disclosure is the responsibility and obligation
of every person involved. Communication System access shall be
designed developed, built, configured and maintained in such a way that
only authorized user have access to the information and to the tool
permitted to execute their job.

(2) The Communication Service Provider’s Information Security department is
responsible for developing, implementing, and maintaining the Access
Policy and the related Procedures. Compliance with this Policy is
mandatory. Non-compliance or violation of this Policy is a serious offense
and may result in the revocation of access to the Communication System.

168. **General Conditions.**

(1) Communication System shall be planned upto the interface points of the
Data provider including the interfacing equipment at the respective
location.

(2) Interface point of the Data Provider shall be substations and generating
stations connected to 110 kV and above, respective LDC control center
including DISCOMs and Market Operator and Service provider (Ancillary,
Weather and Forecast) for the dedicated National wideband backbone
network. However, DISCOM can have their own Communication system
for data and information connectivity for their electrical distribution system
either on wideband or using other mode of Communication system
suitable for operation and maintenance.

(3) Communication service provider shall be responsible for Design and
Engineering, implementation, reliable operation and security of its own
equipment as per the Communication planning criteria and guidelines for development of reliable communication system for the Power System subject to the compliance of operation and maintenance guidelines and other statutory standards.

(4) Central/ State Transmission Utility while planning should consider the intervening Communication service provider design of the Communication system for seamless interfacing of the intervening Communication system to have National Wideband Backbone.

(5) Communication service provider shall ensure Centralized monitoring of its communication network and shall provide necessary facilities for monitoring the system for identification of fault and generation of various reports on availability of the Communication system.

(6) Data Provider shall be responsible for the planning, design, implementation and secured operation of its own equipment to be interfaced with the Communication System.

(7) Data Provider, whose system is proposed to be interfaced with the communication system, shall furnish the Data to the appropriate Control Centre as prescribed by them.

(8) Communication Service Provider, whose system is proposed to be interfaced with the Communication system, shall furnish the requisite information to the Load Despatch Centre as well as to the Market Operator/ Financial Clearing House as per the format prescribed by the appropriate Load Despatch Centre and Market Operator.

(9) These standards are not to be relied upon to protect the plant and equipment of the Data provider or the intervening Communication System Provider.

(10) Every connection/ interfacing with the intervening Communication system shall be covered by a Connection agreement between the parties sharing the Communication service as below:-

   a) Intervening Communication System shall be of State Communication service provider or a Distribution System Communication Provider as the case may be;

   b) Intervening physical communication media provider shall be of Transmission Licensee (Private/ Govt.), JVs as the case may be;

   c) The interface agreement shall contain general and specific technical conditions supported by interfacing details and layout drawings for the interfacing.

169. Site Responsibility.-

   (1) A Site Responsibility Schedule (SRS) for every interface point shall be prepared by the owner of the Data Provider/ Communication Service Provider where interfacing is taking place.
(2) Following information shall be included in the Site Responsibility Schedule, namely, -
   a) Schedule of Telecommunication interface equipment;
   b) Schedule of Auxiliary Power supply equipment catering the Telecommunication equipment;
   c) Schedule of physical and software access, if any;
   d) Schedule of patching details (for example in STM level, E-1 level, TCP/IP level) channel routing;
   e) Schedule of maintenance requirement;
   f) Cyber Security rules applicable to each equipment;
   g) Number of fiber connectivity to the STM;
   h) Type of connectors required for making the connection though;
   i) Any other specific information provided by the Equipment manufacturer;
   j) Any other specific requirement with mutual discussion;
   k) Site/ Node Common Drawings for each interface point.

(3) The following information shall also be furnished in the Site Responsibility Schedule for each item of equipment installed at the interfacing site, namely: -
   a) the ownership of equipment;
   b) the responsibility for access to equipment;
   c) the responsibility for maintenance of equipment;
   d) the responsibility for operation of equipment;
   e) the in charge of the site; and
   f) the responsibility for all matters relating to safety/ security of the equipment at site.

170. Access at Connection Site/ Node.-
The Data Provider or the Intervening Communication Service Provider, as the case may be, owning the interface site/ node shall provide reasonable access and other required facilities to the Communication Service Provider or its authorized representative, whose equipment is installed or proposed to be installed at the interface Site for installation, configuration, testing, operation and maintenance etc. of the equipment.

171. Performance.-
   (1) Volume of data.-
      a) Communication Service Provider shall be capable of transmitting all Operational Data/ Market operation data required by appropriate Control Centre and includes but not limited to all data that,-
         (i) was in use at the time this Standard came into effect;
         (ii) has been requested in writing by appropriate Control Centre
and the Service Provider.

b) The transmission of additional Operational Data beyond that required by Control Centre for System Operation as specified in Indian Electricity Grid Code/State Grid Code or any agreement between System Operator and Data Provider does not diminish the obligations of the Data Provider to comply with this Standard.

(2) **Age of data.**

Operational Data shall be available from all the Data Providers in response to a poll within the time intervals specified in the following **Tables.** The time interval is calculated from the instant, the data first gets converted to digital form.

### Table 1

<table>
<thead>
<tr>
<th>Category</th>
<th>Data Type</th>
<th>Time Interval (seconds)</th>
<th>Time Interval via Data Concentrator (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGC Signal</td>
<td>Analog Value</td>
<td>2 2 3</td>
<td>2 2 3</td>
</tr>
<tr>
<td>Despatch Data</td>
<td>Status Indication</td>
<td>2 3 4</td>
<td>2 3 5</td>
</tr>
<tr>
<td></td>
<td>Analog Value</td>
<td>4 5 6</td>
<td>4 5 7</td>
</tr>
<tr>
<td>PMU Data</td>
<td>Analog</td>
<td>0.04 0.04</td>
<td>0.04 0.04</td>
</tr>
</tbody>
</table>

### Table 2

<table>
<thead>
<tr>
<th>Category</th>
<th>Data Type</th>
<th>Time Interval (seconds)</th>
<th>Time Interval via Data Concentrator (seconds)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Forecast Data</td>
<td>Value</td>
<td>60 60 60</td>
<td>60 60 60</td>
</tr>
<tr>
<td>Weather Data</td>
<td>Value</td>
<td>60 60 60</td>
<td>60 60 60</td>
</tr>
<tr>
<td>Market Data</td>
<td>Value</td>
<td>60 60 60</td>
<td>60 60 60</td>
</tr>
</tbody>
</table>
(3) **Control command delay.**
Communication System shall relay the Control Command from the Control Centre to relevant equipment within 2 seconds, whether the command is transmitted directly or via a Data Concentrator.

172. **Reliability.**

1. The total period of outages for Data Provider’s interface shall be less than 12 hours on monthly basis and the total outages in a rolling 12-month assessment period shall be less than 36 hours. Data Provider shall maintain adequate redundancy, while designing the system, to attain the same.
2. The total period of outages for the Wideband node shall be less than 12 hours on monthly basis and the total outages in a rolling 12 month assessment period shall be less than 36 hours.
3. The total period of outages for the Communication media shall be less than 12 hours on monthly basis and the total outages in a rolling 12 months assessment period shall be less than 36 hours.
4. Communication Service Provider shall have above redundancy while designing the system taking into account the following:
   - a) Route diversity required to take care likely failure of the physical path;
   - b) The likely failure rate of their element;
   - c) The likely time to repair for their elements;
   - d) The assessment for planned outages for their elements;
   - e) Any other required factor.

173. **Cyber Security.**

1. Data Provider, Communication Service Provider and Control Centre Owner connected to the Communication system shall have robust programs in place to adequately and continuously manage cyber security risks that could adversely impact Power system Communications, supporting system and infrastructure.
2. The cyber security program should use reasonable endeavors to address the following functions:
   - a) Understanding of cyber security risks to the systems, assets and risk assessment; and implement risk management strategies;
   - b) To have controls and safeguards necessary to protect or deter cyber security threats with implementation of access control, data security, data protection;
   - c) Continuous monitoring to provide proactive and real time alerts of cyber security related events;
   - d) Analysis of observation(s) related to various activities related to violation of cyber security; and implement mitigation policy;
   - e) Business continuity plans/ Disaster Management Plan to maintain resilience and recovery capabilities after a cyber-breach;
(f) Adequate training to the persons, who are authorized to have access to the Communication system, on cyber security to continuously update the threat perception;

(g) Carry out cyber security audit within predefined interval, through Govt. approved agencies to ensure security;

(h) Implementation of relevant provision(s) contained in the Cyber Security Policy issued by Govt. of India from time to time.

(3) SLDC shall monitor case of cyber security incidences and take necessary action as deemed fit.

(4) SLDC shall ensure that third party cyber security audits are conducted periodically and appropriate measures are implemented to comply with the findings of the audits. The audits shall be conducted by CERT-In certified third party auditors.

174. Safety of Communication Equipment.-

(1) Communication Service Provider shall be responsible for the safety of its equipment installed at the premises as well as equipment located outside the premises of Data Provider, Control Centre Owner.

(2) Data Provider, Control Centre Owner and Market operator shall be responsible for the safety of the Communication equipments installed by them for interfacing with the equipment installed by the Communication service provider.

175. Testing to confirm compliance.-

(1) Testing shall be carried out as and when the equipments of Data Providers, the Communication Service Provider, intervening Communication System Provider, and the Control Center or of other service provider’s, are replaced/ upgraded to confirm the compliance to these standards.

(2) Prior to test, the concerned person, who intend to upgrade/ replace the Communication equipment shall;
   a) Coordinate with all the concerned for relaying the data to be tested;
   b) Prepare and submit a test procedure for the testing to all the concerned;
   c) Submit detailed equipment test report to SLDC/ STU for compliance.

176. Site Common Drawings.-

Site/ Node Common Drawings shall be prepared for each interface point where connection is taking place by the Communication Service Provider jointly in coordination with the Users/ Service Provider.

177. Maintenance.-

(1) Communication Service Provider shall have a centralized monitoring facility to support the maintenance activity.
(2) The response time to failure shall be decided to maintain the outage time specified under Regulation 171 of this Code.

(3) Monthly Outage plan may be planned and approved by concerned Communication Service Provider with SLDC/STU as per detailed procedure finalized.

(4) Notice to be issued to the concerned Data Provider, the SLDC/Service Provider/Market Operator, five days before a planned outage of any of the service, likely to cause failure of data Communication.

(5) SLDC/Service Provider/Market Operator may defer the request in case it will adversely affect the Power System Security.

(6) Inform the progress of related rectification work to Data Provider as well as to SLDC/Service Provider/Market Operator.

(7) Consult with the SLDC/Service Provider/Market Operator about the priority of the related rectification works in case the failure is causing or likely to cause Outage.

178. Periodic Auditing of Communication System.-

The SLDC shall conduct performance audit of Communication system annually as per the procedure finalized by SLDC/STU. Based on the audit report, SLDC shall issue necessary instructions to all stakeholders to comply with the audit requirements within the time stipulated. An Annual Report on the audit carried out by SLDC shall be submitted to the SGCRC within one month of ending of the financial year.

179. Fault Reporting.-

(1) SLDC in case of outage of telemeter data, or Communication failure shall inform the respective user so that the user shall ensure healthiness of its communication system. In case outage pertains to fault in Communication system of other user, the user shall lodge complaint for failure of the communication to the communication system owner for quick restoration.

(2) The Communication provider shall explore the possibility for route diversion on the existing facility in close co-ordination with concerned provider in case the fault restoration is prolonged. No separate charges shall be paid for such route diversion or channel re-allocation. However, such rerouting shall be discontinued once the original channel is restored.

180. Communication System Availability.-

All Users, SLDC and STU shall maintain the Communication channel availability at 99.9% annually and with back up Communication system, the availability of Communication system should be 100%.
Part XVIII

DATA REGISTRATION

181. Introduction.-

(1) This part contains a list of all data required by STU and SLDC, which is to be provided by Users, and the data required by Users to be provided by STU at times specified in the State Grid Code. It also provides the details of mandatory registration of generating units with CEA.

(2) The objective of this section is to list out all the data required to be provided by Users to STU and/or SLDC and vice versa, in accordance with the provisions of the State Grid Code. It also list out the details to be provided to CEA for mandatory registration of generating units.

182. Responsibility,-

(1) All Users are responsible for submitting up-to-date data to STU/ SLDC in accordance with the provisions of the State Grid Code.

(2) All generating companies are responsible for registering all the generating units of capacity >500kW, with the National Level Data Registry System maintained by CEA.

(3) All Users shall provide STU and SLDC with the name, address, e-mail and telephone number of the person responsible for sending the data.

(4) STU shall inform all Users and SLDC of the name, address, e-mail and telephone number of the person responsible for receiving data.

(5) STU shall provide up-to-date data to Users as provided in the relevant schedule of the State Grid Code.

(6) Responsibility for the correctness of data rests with the concerned User providing the data.

183. Data categories and stages in Registration.-

(1) Data required to be exchanged has been listed in the Appendices under various categories with cross reference to the concerned Sections.

(2) Changes to User’s Data,-

Whenever any User becomes aware of a change to any items of data that is registered with STU, the User must promptly notify STU of the changes. STU on receipt of intimation of the changes shall promptly correct the database accordingly. This shall also apply to any data compiled by STU regarding its own system.

(3) Methods of Submitting Data,-

a) The data shall be furnished in the standard formats for data submission and such formats must be used for the written submission of data to SLDC/ STU.

b) Where standard formats are not enclosed these would be developed by SLDC / STU in consultation with Users.
c) All data to be submitted under the Schedule(s) must be submitted to SLDC / STU or to such other department and/ or entity as STU may from time to time notify to Users. The name of the Person who is submitting each schedule of data must be indicated.

d) Where a computer data link exists between a User and SLDC/ STU, data may be submitted via this link. The data shall be in the same Excel (.xls/.xlsx) format as specified for paper transmission. Electronic encoding shall be made accordingly.

e) The User shall specify the method to be used in consultation with the SLDC/ STU and resolve issues such as Protocols, transmission speed etc. at the time of transmission. Other modes of data transfer, such as compact disc, hard disc or magnetic tape may be utilized, if SLDC/ STU give its prior written consent.

4) Data not supplied,

a) Users are obliged to supply data as referred to in the individual sections of the State Grid Code and listed out in the Data Registration section Appendices.

b) In case any data is not supplied by any User or is not available, STU or SLDC may, acting reasonably if and when necessary, estimate such data depending upon the necessity of the situation.

c) Similarly, in case any data is not supplied by STU, the concerned User may, acting reasonably if and when necessary, estimate such data depending upon the necessity of the situation.

d) Such estimates will in each case, be based upon corresponding data for similar plant or Apparatus or upon such other information, the User or STU or SLDC, as the case may be, deemed appropriate.

184. Special Considerations.-

STU and SLDC and any other User may at any time make reasonable request for extra data as necessary. STU shall supply data, required/ requested by SLDC for system operation, from data bank to SLDC.

185. Data Acquisition.-

1. The following real time data are required by SLDC for effective control of the power system:
   (a) MW and MVAR generated or absorbed in each generating station;
   (b) MVAR imported or exported from the external connections;
   (c) Voltages in all the system bus bar;
   (d) Frequency in the system;
   (e) MW and MVAR flow in each Transmission element;
   (f) Weather data viz. Temperature, Wind Speed and direction, Humidity etc.;
   (g) Tap position of Transformer, Breaker/ Isolator status points.

2. The generating companies/ users shall provide the necessary RTU/ Communication gateway or Interface point for the transmission of the above data from their generating stations to SLDC.
(3) STU/ CTU/ Transmission Licensee shall similarly provide the necessary RTU/ Communication gateway or Interface point from SCADA, for the transmission of the above data from their receiving stations and substations to SLDC.

(4) STU shall establish a suitable data transfer link between Backup LDC to SLDC, SLDC to SRLDC and BSLDC to Backup NLDC, for exchange of operational data transmission.

(5) Mutually agreed procedures shall be drawn up between the SLDC and STU/ Transmission Licensee/ Generating Station and other users outlining inter responsibility, accountability and recording of day-to-day communications and data transmission on operational matters.

(6) The RTU/ SCADA facility should have GPS Time synchronization and Time stamping facility on all data communicated to SLDC. Geographical Positioning Systems (GPS) may be used for time stamping of the trip information at the respective stations.

186. **Registration of Generating Units.**

Section 74 of Electricity Act, 2003 and Regulations 4 and 5 of CEA (Furnishing of statistics, returns and information) Regulations, 2007, mandates every licensee, generating company, or person(s) generating electricity for its or his own use to furnish the statistics, returns or other information relating to Generation, Transmission, Distribution, Trading to CEA. Hence, mandatory registration of all the electricity generating units, above a specified capacity (>0.5MW), through the National Level Data Registry System established by CEA, by assigning each of them a unique registration number, is necessary. The registration number to be assigned by CEA shall be unique for each generating unit in the country and the registration number once assigned to a generating unit would not be changed. The status of generating unit may change (planned/ under construction/ commissioned/ retired etc.). Even if the generating unit retires, its registration number would not be assigned to any other generating unit.

187. **Applicability,**

(1) The following category of generating units are required to obtain the unique registration number:

   i) All the conventional grid connected electricity generating units (whether in Central Sector, State Sector, Private Sector, IPP’s, Joint Venture etc.) in the country, whether coal based, gas based, liquid fuel based, Hydro Power based or Nuclear, if the capacity of the electricity generating unit is 500 kW (0.5 MW) and above.
ii) All the electricity generating units of grid-connected captive power plants, if the capacity of the electricity generating unit is 500 kW (0.5 MW) and above.

iii) All the Grid connected Renewable Energy (RE) generators, if the capacity of RE generating unit is 500 kW (0.5 MW) or above. This also includes grid connected roof top solar installations.

iv) All the stand alone (off grid) generating units, if the capacity of generating unit is 500 kW (0.5 MW) or above.

v) All the generating units supplying power to neighbouring countries, irrespective of whether these generating units are connected to the Indian Electricity Grid or not.

(2) For existing grid connected electricity generating units, including grid connected captive and RES generating units, the registration number would be required for injecting power in the grid.

(3) For under construction electricity generating units and generating units in conceptualization stage, which includes grid connected captive and RES generating units, the registration number would be required while applying for grid connectivity. However, if grid connectivity has already been obtained or applied by these generating units, the registration number would still be required for physical injection of power in the grid.

188. Procedure of Registration.-

i) The registration number would be generated online by the generating companies/ project developers, after filling in certain details.

ii) The Generating Companies would have to register themselves in e-Registration portal of CEA on CEA’s website (www.cea.nic.in) after filling in necessary details viz. name of the generating company, sector etc. in a format designed for the purpose. They can choose any user id and password while registering their generating units. Alternatively, user ID may be the name of the Company.

iii) Using the user id and password generated, generating companies can enter the details of their generating units one by one and generate unique registration number for each generating unit. The unique registration number shall be a 10 digit numeric identification number in the format XXXXXXXXX. The first digit will indicate whether it is Generating Company, Transmission Company or Distribution Company (Generating Company -1; Transmission Company -2; Distribution Company -3). In case of Generating Company the second digit will indicate the type of generating unit (Hydro-1/ Thermal-2/ Nuclear-3/ RES-4). Digits from 3-10 (8 digits) would be the unique registration number of the generating unit.
iv) All the information associated with a generating unit will be linked with this unique registration number. All the associated information like location of the generating unit, fuel type, technology (sub critical, supercritical, ultra-supercritical, off-shore wind, on-shore wind, roof top solar, solar thermal, floating solar etc.), installed capacity, sector (central, state, private, JV), utility or captive, grid connected or off-grid etc. will be available in the database and will be visible to the authorized persons, once the registration number is entered.

189. The Generating companies/ Project developers would submit the following data/information at the time of registering their generating units:

(1) **Existing Generating Units.**

a) **Mandatory Information to be filled at the time of Registration,**

i) Name of the generating unit;
ii) Capacity of the Generating unit in MW;
iii) State, Location and Address (including District) of the Generating Unit;
iv) Latitude and Longitude of the Generating Unit;
v) Name of Owner (s) along with contact details including telephone, mobile, e-mail and fax;
vi) Name and contact details of person, including telephone, mobile, e-mail and fax number, to be contacted for clarifications, if required;
vii) Sector, whether Central/State/Private/JV;
viii) Whether the generating unit is grid connected or off grid;
ix) Fuel type of generating unit (Coal/ lignite/ gas/ diesel/ HFO/ Other Liquid Fuel/ nuclear/ hydro/ solar/ wind/ biomass/ Coal Reject / Wind-Solar Hybrid etc.);
x) Type of technology viz. Sub-critical/ Super-critical technology/ Ultra-supercritical technology in case of coal based generating unit; OCGT, CCGT, Gas Engines etc. in case of gas based generating unit;
xi) Type of hydro viz. ROR, Pondage, Storage, Pumped Storage;
xii) Date of commissioning of the generating unit;
xiii) Date of Commercial Operation (COD) of the generating unit;
xiv) Fuel linkage/ source of fuel, if applicable;
xv) Name of the Industry/ Installation, in case of Captive Generating units.

b) **Information to be furnished subsequently,**

i) Implementing Agency;
ii) BTG Supplier in case of thermal generating units;
iii) E&M, HM equipment supplier in case of Hydro generating units;
iv) Type of hydro turbine viz. Pelton, Francis, Kaplan, Bulb, any other
v) Ramp Up/ Down rate of the generating unit;
v) Minimum technical loading of the generating unit;
vi) Whether the generating unit is connected to ISTS or State Grid;
vii) Voltage level at which generating unit is connected to the ISTS/ State Grid.

(2) Generating units under Construction.-
   a) Mandatory Information to be filled at the time of Registration.-
      i) Name of the generating unit;
      ii) Capacity of the Generating unit in MW;
      iii) State, Location and Address (including District) of the Generating Unit;
      iv) Latitude and Longitude of the Generating Unit;
      v) Name of Owner(s) along with contact details including telephone, mobile, e-mail and fax;
      vi) Name and contact details of person, including telephone, mobile, e-mail and fax number, to be contacted for clarifications, if required;
      vii) Sector, whether Central/ State/ Private/ JV;
      viii) Whether the generating unit is grid connected or off-grid;
      ix) Fuel type of generating unit (Coal/ lignite/ gas/ diesel/ nuclear/ hydro/ solar/ wind/ biomass/ Coal Reject/ Wind-solar hybrid etc.);
      x) Type of technology viz. Sub-critical/ super-critical technology/ ultra-super-critical technology in case of coal based generating unit; OCGT, CCGT etc. in case of gas based generating unit;
      xi) Type of hydro viz. ROR, Pondage, Storage, Pumped Storage;
      xii) Letter of Award (LoA) Date:
          (a) BTG package for thermal generating units;
          (b) Main Civil, E&M and HM packages in case of Hydro generating units.
      xiii) Expected commissioning date of the generating unit;
     xiv) Expected Date of Commercial Operation (COD) of the generating unit;
      xv) Fuel linkage/ source of fuel, if applicable;
      xvi) Type of technology viz. Sub-critical/ Super-critical technology/ Ultra-super-critical technology in case of coal based generating unit;
      xvii) Name of the Industry/ Installation, in case of Captive Generating units.

b) Information to be furnished subsequently,-
   i) Implementing Agency;
   ii) BTG Supplier in case of thermal generating units;
   iii) E&M, HM equipment supplier in case of Hydro generating units;
   iv) Type of hydro turbine viz. Pelton, Francis, Kaplan, Bulb etc.;
   v) Ramp Up/ down rate of the generating unit;
   vi) Minimum technical loading of the generating unit;
   vii) Whether the generating unit is connected to ISTS or State Grid;
   viii) Voltage level at which generating unit is connected to the ISTS/ State Grid.
(3) Generating units in Conceptualization stage.

a) Mandatory Information to be filled at the time of Registration.

i) Name of the generating unit;
ii) Capacity of the Generating unit in MW;
iii) State, Location and Address (including District) of the Generating Unit;
iv) Latitude and Longitude of the Generating Unit;
v) Name of Owner(s) along with contact details including telephone, mobile, e-mail and fax;
vi) Name and contact details of person, including telephone, mobile, e-mail and fax number, to be contacted for clarifications, if required;
vii) Sector, whether Central/ State/ Private/ JV;
viii) Fuel type of generating unit (Coal/ lignite/ gas/ diesel/ nuclear/ hydro/ solar/ wind/ biomass/ Coal reject/ Wind-solar Hybrid etc.);
ix) Whether the generating unit is grid connected or off-grid;
x) Type of technology viz. Sub-critical/ super-critical technology/ ultra-super-critical technology in case of coal based generating unit;
OCGT, CCGT etc. in case of gas based generating unit;
xii) Type of hydro viz. ROR, Pondage, Storage, Pumped Storage;
xiii) Expected commissioning date of the generating unit, if available;
xiv) Name of the Industry/ Installation, in case of Captive Generating units.

b) Information to be furnished subsequently.

i) BTG Supplier in case of thermal generating units;
ii) E&M, HM equipment supplier in case of Hydro generating units;
iii) Type of hydro turbine viz. Pelton, Francis, Kaplan, Bulb etc.;
iv) Likely source of fuel, if applicable;
v) Ramp Up/ Down rate of the generating unit;
vi) Minimum technical loading of the generating unit;
vii) Whether the generating unit is proposed to be connected to ISTS or State Grid;
viii) Voltage level at which generating unit is proposed to be connected to the ISTS/ State Grid.

190. Registration of Transmission and Distribution System.

The registration of Transmission system (existing, under construction and planned) and Distribution system (existing, under construction and planned) and its data shall be furnished by the respective Transmission and Distribution Licensees, to the National Level Data Registry system as and when the registration process for the same is conceptualized by CEA.
PART XIX

MISCELLANEOUS

191. **Power to Remove Difficulties.**

If any difficulty arises in giving effect to any provisions of this Code, the Commission may by general or special order, direct the STU, SLDC and the User(s) to take such action as may appear to the Commission to be necessary or expedient for the purpose of removing the difficulties.

192. **Power to Relax.**

The Commission may, for reasons to be recorded in writing, relax any of the provisions of this Code, not being inconsistent with the provisions of the Act.

193. **General Power to Amend.**

The Commission may, at any time and on such terms as it may deem fit; amend any of these Regulations for the purpose of meeting the objectives with which these Regulations have been framed.

194. **Repeal and Saving.**

1. The Kerala State Electricity Grid Code, 2005 shall stand repealed from the date of commencement of these Regulations.

2. Notwithstanding such repeal, anything done or purported to have been done under the repealed Regulations shall be deemed to have been done or purported to have been done under these Regulations.
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<tr>
<th>LIST OF APPENDIX</th>
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</thead>
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<td>A.2: Transmission</td>
</tr>
<tr>
<td>A.3: Distribution</td>
</tr>
<tr>
<td><strong>APPENDIX B</strong> : Detailed Planning Data</td>
</tr>
<tr>
<td>B.1: Generation</td>
</tr>
<tr>
<td>B.2: Transmission</td>
</tr>
<tr>
<td>B.3: Distribution</td>
</tr>
<tr>
<td><strong>APPENDIX C</strong> : Operational Planning Data</td>
</tr>
<tr>
<td>(C.1 to C.6)</td>
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<td><strong>APPENDIX D</strong> : Site Responsibility Schedule</td>
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<td><strong>APPENDIX E</strong> : Intimation of Incident</td>
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<td><strong>APPENDIX F</strong> : (a) Requisition for PTW</td>
</tr>
<tr>
<td>(b) Check list for PTW/ LCP &amp; LCP</td>
</tr>
<tr>
<td>(c) Form for PWR/ LCR</td>
</tr>
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<td><strong>APPENDIX G</strong> : Scheme for payment of Reactive Energy Exchange</td>
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<tr>
<td><strong>APPENDIX H</strong> : Methodology for relay setting of Transmission lines</td>
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<td>(Uncompensated)</td>
</tr>
<tr>
<td><strong>APPENDIX I</strong> : Methodology for relay setting of Transmission lines</td>
</tr>
<tr>
<td>(Series compensated)</td>
</tr>
<tr>
<td><strong>APPENDIX J</strong> : General Information to be provided for Protection Audit</td>
</tr>
</tbody>
</table>
APPENDIX A - STANDARD PLANNING DATA

Standard Planning Data consist of details, which are expected to be normally sufficient for STU to investigate the impact on the State Transmission System due to User development.

A.1- STANDARD PLANNING DATA (Generation)

A.1.1 SGS THERMAL (Coal/Gas/Fuel linked)

A.1.1.1 General

| (i) | Site | Give location map to scale showing roads, railway lines, Transmission lines, canals, pondage and reservoirs, if any. |
| (ii) | Coal linkage/Fuel (LNG, Naphtha etc.) linkage | Give information on means of coal transport/carriage. In case of other fuels, give details of source of fuel and their transport. |
| (iii) | Water Sources | Give information on availability of water for operation of the Power Station. |
| (iv) | Environmental | State whether forest or other land areas are affected. |
| (v) | Site Map (To Scale) | Showing area required for Power Station coal linkage, coal yard, water pipe lines, ash disposal area, colony etc. |
| (vi) | Approximate period of Construction | |

A.1.1.2 Connectivity

| (i) | Point of Connection | Give single line diagram of the proposed Connection with the system. |
| (ii) | Step up voltage for Connectivity (kV) | |

A.1.1.3 Station Capacity

| (i) | Total Power Station capacity (MW) | State whether development will be carried out in phases and if so, furnish details |
| (ii) | No. of units and unit size (MW) | |
## A.1.1.4 Generating Unit Data

<table>
<thead>
<tr>
<th></th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>(i)</td>
<td>Steam Generating Unit (Type, capacity, steam pressure, steam temperature etc.)</td>
</tr>
<tr>
<td>(ii)</td>
<td>Steam turbine (type, capacity)</td>
</tr>
</tbody>
</table>
| (iii) | **Generator**  
Type  
Rating (MVA)  
Speed (rpm)  
Terminal voltage (kV)  
Rated Power Factor  
Reactive Power Capability (MVAR) from pf 0.95 leading to 0.85 lagging  
Short Circuit Ratio  
Direct axis (saturated) transient reactance (% on MVA rating)  
Direct axis (saturated) sub-transient reactance ( % on MVA rating)  
Auxiliary Power requirement (MW)  
MW and MVAR Capability Curve  
Ramp-up and ramp-down rate  
Generator Characteristic Curve |
| (iv) | **Generator Transformer**  
Type  
Rated capacity (MVA)  
Voltage Ratio (HV/LV)  
Tap change Range step-wise (+ % to - %)  
Percentage Impedance (Positive Sequence at Full load) |
## A.1.2 SGS HYDRO ELECTRIC

### A.1.2.1 General

<table>
<thead>
<tr>
<th>(i)</th>
<th>Site</th>
<th>Give location map to scale showing roads, railway lines and transmission lines</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Site map (To scale)</td>
<td>Showing proposed canal, reservoir area, water conductor system, fore-bay, power house etc.</td>
</tr>
<tr>
<td>(iii)</td>
<td>Submerged Area</td>
<td>Give information on area submerged, villages submerged, submerged forest land, agricultural land etc.</td>
</tr>
<tr>
<td>(iv)</td>
<td>Whether storage type or run of river type</td>
<td></td>
</tr>
<tr>
<td>(v)</td>
<td>Whether catchment receiving discharges from other reservoir or power plant.</td>
<td></td>
</tr>
<tr>
<td>(vi)</td>
<td>Full reservoir level</td>
<td></td>
</tr>
<tr>
<td>(vii)</td>
<td>Minimum draw down level</td>
<td></td>
</tr>
<tr>
<td>(viii)</td>
<td>Tail race level</td>
<td></td>
</tr>
<tr>
<td>(ix)</td>
<td>Design Head</td>
<td></td>
</tr>
<tr>
<td>(x)</td>
<td>Reservoir level v/s energy potential curve</td>
<td></td>
</tr>
<tr>
<td>(xi)</td>
<td>Constraints, if any, in water Discharge</td>
<td></td>
</tr>
<tr>
<td>(xii)</td>
<td>Approximate period of Construction</td>
<td></td>
</tr>
</tbody>
</table>

### A.1.2.2 Connectivity

<table>
<thead>
<tr>
<th>(i)</th>
<th>Point of Connection</th>
<th>Give single line diagram of proposed Connection with the Transmission System.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Step up voltage for Connectivity (kV)</td>
<td></td>
</tr>
</tbody>
</table>

### A.1.2.3 Station Capacity

<table>
<thead>
<tr>
<th>(i)</th>
<th>Total Power Station capacity (MW)</th>
<th>State whether development is carried out in phases and if so furnish details.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>No. of units and unit size (MW)</td>
<td></td>
</tr>
</tbody>
</table>

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A.1.2.4 Generating Unit Data

| (i) | Operating Head (in Metres) | a) Maximum  
b) Minimum  
c) Average |
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Hydro Unit</td>
<td></td>
</tr>
<tr>
<td>a)</td>
<td>Capability to operate as synchronous condenser</td>
<td></td>
</tr>
<tr>
<td>b)</td>
<td>Water head versus discharges curve (at full and part load)</td>
<td></td>
</tr>
<tr>
<td>c)</td>
<td>Power requirement or water discharge while operating as synchronous condenser</td>
<td></td>
</tr>
<tr>
<td>(iii)</td>
<td>Turbine (Type and capacity)</td>
<td></td>
</tr>
<tr>
<td>(iv)</td>
<td>Generator</td>
<td></td>
</tr>
<tr>
<td>a) Type</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b) Rating (MVA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>c) Speed (RPM)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>d) Terminal voltage (kV)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>e) Rated Power Factor</td>
<td></td>
<td></td>
</tr>
<tr>
<td>f) Reactive Power Capability (MVAR)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>g) MW and MVAR capability curve of Generating unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td>h) Short Circuit Ratio</td>
<td></td>
<td></td>
</tr>
<tr>
<td>i) Direct axis transient (saturated) reactance (% on rated MVA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>j) Direct axis sub-transient (saturated) reactance (% on rated MVA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>k) Auxiliary Power Requirement (MW)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(v)</td>
<td>Generator Transformer</td>
<td></td>
</tr>
<tr>
<td>a) Type</td>
<td></td>
<td></td>
</tr>
<tr>
<td>b) Rated Capacity (MVA)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>c) Voltage Ratio HV/LV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>d) Tap change Range Step-Wise (+% to - %)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>e) Percentage Impedance (Positive Sequence at Full Load).</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
A.2 - STANDARD PLANNING DATA (Transmission)

STU is responsible for compilation of the data and update periodically. The different departments of STU and other transmission licensees (if any) have to provide the data to the planning department of STU to update the Standard Planning Data, in the format given below:

(i) Name of line (Indicating Power Stations and substations to be connected).
(ii) Voltage of line (kV).
(iii) No. of circuits.
(iv) Route length (km).
(v) Conductor sizes.
(vi) Line parameters (Per Unit values).
(vii) Resistance/ km
(viii) Inductance/ km
(ix) Susceptance/ km
(x) Approximate power flow expected - MW and MVAR
(xi) Terrain of the route - Give information regarding nature of terrain i.e. forest land, fallow land, agricultural and river basin, hill slope etc.
(xii) Route map (to scale) - Furnish topographical map showing the proposed route showing existing power lines and telecommunication lines.
(xiii) Purpose of Connection - Reference to Scheme, wheeling to other States etc.
(xiv) Approximate period of Construction.
(xv) Maximum conductor temperature for which the line is designed.
A.3- STANDARD PLANNING DATA (Distribution)
(For Distribution licensees)

A.3.1 General

<table>
<thead>
<tr>
<th>(i)</th>
<th>Area Map (to scale)</th>
<th>Furnish map of Kerala state duly marked with the area of supply relevant for the Distribution Licensee.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Consumer Data</td>
<td>Furnish categories of consumers, their numbers and connected loads.</td>
</tr>
<tr>
<td>(iii)</td>
<td>Reference to</td>
<td></td>
</tr>
<tr>
<td></td>
<td>distribution divisions</td>
<td></td>
</tr>
</tbody>
</table>

A.3.2 Connectivity

<table>
<thead>
<tr>
<th>(i)</th>
<th>Points of Connection</th>
<th>Furnish single line diagram showing points of Connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Voltage of supply at points of Connection</td>
<td></td>
</tr>
<tr>
<td>(iii)</td>
<td>Name of Grid Substations feeding the points of Connection</td>
<td></td>
</tr>
</tbody>
</table>

A.3.3 Lines and Substations

<table>
<thead>
<tr>
<th>(i)</th>
<th>Line Data</th>
<th>Furnish lengths of line within the Area, its laying (overhead / underground), conductor / cable size, bundle spacing of conductors, phases and voltages</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Substation Data</td>
<td>Furnish details of 66/11 kV sub-station, 33/11 kV sub-station, 11/0.4 kV sub-stations, transformer capacity with vector group, capacitor installations</td>
</tr>
</tbody>
</table>

A.3.4 Loads

<table>
<thead>
<tr>
<th>(i)</th>
<th>Load drawn at points of Connection.</th>
</tr>
</thead>
<tbody>
<tr>
<td>(ii)</td>
<td>Details of loads fed at EHV, if any. Give name of consumer, voltage of supply, contract demand/ load and name of Grid Substation from which line is drawn, length of EHV line from Grid Substation to consumer's premises</td>
</tr>
<tr>
<td>(iii)</td>
<td>Reactive Power compensation installed</td>
</tr>
</tbody>
</table>

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### A.3.5 Demand Data (for all loads 1 MW and above)

<p>| | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(i)</td>
<td>Type of load</td>
<td>State whether furnace loads, rolling mills, traction loads, continuous process load, pumping loads, other industrial loads etc.</td>
</tr>
<tr>
<td>(ii)</td>
<td>Rated voltage and phase</td>
<td></td>
</tr>
<tr>
<td>(iii)</td>
<td>Electrical loading of equipment</td>
<td>State number and size of motors, types of drive and control arrangements</td>
</tr>
<tr>
<td>(iv)</td>
<td>Power Factor</td>
<td></td>
</tr>
<tr>
<td>(v)</td>
<td>Sensitivity of load to voltage and frequency of supply</td>
<td></td>
</tr>
<tr>
<td>(vi)</td>
<td>Maximum Harmonic content of load</td>
<td></td>
</tr>
<tr>
<td>(vii)</td>
<td>Average and maximum phase unbalance of load</td>
<td></td>
</tr>
<tr>
<td>(viii)</td>
<td>Nearest substation from which load is to be fed</td>
<td></td>
</tr>
<tr>
<td>(ix)</td>
<td>Location map to scale</td>
<td>Showing location of load with reference to lines and substations in the vicinity</td>
</tr>
<tr>
<td>(x)</td>
<td>Sanctioned load of continuous process industries</td>
<td></td>
</tr>
</tbody>
</table>

### A.3.6 Load Forecast Data

<p>| | | |</p>
<table>
<thead>
<tr>
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</thead>
<tbody>
<tr>
<td>(i)</td>
<td>Peak load and energy forecast for each category of loads for each of the succeeding 5 years.</td>
<td></td>
</tr>
<tr>
<td>(ii)</td>
<td>Details of methodology and assumptions on which forecasts are based</td>
<td></td>
</tr>
<tr>
<td>(iii)</td>
<td>If supply is received from more than one substation, the substation wise break up of peak load and energy projections for each category of loads for each of the succeeding 5 years along with estimated Daily load curve.</td>
<td></td>
</tr>
<tr>
<td>(iv)</td>
<td>Details of loads 1 MW and above:</td>
<td></td>
</tr>
<tr>
<td></td>
<td>a. Name of prospective consumer.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>b. Location and nature of load/ complex</td>
<td></td>
</tr>
<tr>
<td></td>
<td>c. Substation from which to be fed</td>
<td></td>
</tr>
<tr>
<td></td>
<td>d. Voltage of supply</td>
<td></td>
</tr>
<tr>
<td></td>
<td>e. Phasing of load</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX B - DETAILED PLANNING DATA

B.1- DETAILED PLANNING DATA (Generation)

B.1.1 SGS Thermal Power Stations

B.1.1.1 General

i) Name of Power Station.

ii) Number and capacity of Generating Units (MVA/ MW).

iii) Ratings of all major equipments (Boilers and major accessories, Turbines, Alternators, Generator Unit Transformers etc).

iv) Single line Diagram of Power Station and switchyard.

v) Relaying and metering diagram.

vi) Neutral Grounding of Generating Units.

vii) Excitation control type used i.e. Thyristor, Brushless Exciter etc.)

viii) Earthing arrangements with earth resistance values

B.1.1.2 Protection and Metering

(i) Full description including settings for all relays and protection systems installed on the Generating Unit, Generator unit Transformer, Auxiliary Transformer and electrical motors of major equipments listed, but not limited to, under Sec. 4 (General).

(ii) Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, tie circuit breakers, and incoming circuit breakers.

(iii) Full description of inter-tripping of circuit breakers at the point or points of Connection with the Transmission System.

(iv) Most probable fault clearance time for electrical faults on the User's System (with main and back up protection).

(v) Full description of operational and commercial metering schemes

B.1.1.3 Switchyard

(i) **Interconnecting transformers:**

- Rated MVA.
- Voltage Ratio.
- Vector Group.
- Positive sequence reactance for max., min., normal Tap (% on MVA).
- Positive sequence resistance for max., min., normal Tap (% on MVA).
- Zero sequence reactance (% on MVA).
- Tap changer Range (+% to - %) and steps.
- Type of Tap changer (off/ on load).

(ii) **Switchgear** including circuit breakers, isolators on all circuits connected to the points of Connection:
- Rated voltage (kV).
- Type of circuit breaker (MOCB/ ABCB/ SF6).
- Rated short circuit breaking current (kA) 3 phase.
- Rated short circuit breaking current (kA) 1 phase.
- Rated short circuit making current (kA) 3 phase.
- Rated short circuit making current (kA) 1 phase.
- Provisions of auto reclosing with details.

(iii) **Lightning Arresters**

Number and location (line / transformer) with Technical data.

(iv) **Communication System**

Details of PLCC communication equipment installed at points of connections / Interface points.

(v) **Basic Insulation Level (kV):**
- Bus bar.
- Switchgear.
- Transformer bushings.
- Transformer windings.

**B.1.1.4 Parameters of Generating Units**

(i) Rated terminal voltage (kV).
(ii) Rated MVA.
(iii) Rated MW.
(iv) Speed (rpm) or number of poles.
(v) Inertia constant H (MW sec /MVA).
(vi) Short circuit ratio.
(vii) Direct axis synchronous reactance (% on MVA) Xd.
(viii) Direct axis (saturated) transient reactance (% on MVA) Xd'.
(ix) Direct axis (saturated) sub-transient reactance (% on MVA) Xd".
(x) Quadrature axis synchronous reactance (% on MVA) $X_q$.
(xi) Quadrature axis (saturated) transient reactance (% on MVA) $X'_q$.
(xii) Quadrature axis (saturated) sub-transient reactance (% on MVA) $X''_q$.
(xiii) Direct axis transient open circuit time constant (sec) $T_{do}$.
(xiv) Direct axis sub-transient open circuit time constant (sec) $T''_{do}$.
(xv) Quadrature axis transient open circuit time constant (sec) $T'_{qo}$.
(xvi) Quadrature axis sub-transient open circuit time constant (sec) $T''_{qo}$.
(xvii) Stator Resistance (Ohm)
(xviii) Neutral grounding details.
(xix) Stator leakage reactance (Ohm)
(xx) Stator time constant (sec).
(xxi) Rated Field current (A).
(xxii) Open Circuit saturation characteristic for various terminal Voltages giving the compounding current to achieve the same.
(xxiii) MW and MVA Capability Curve.
(xxiv) Rated Stator Current (A).

**B.1.1.5 Parameters of excitation control system:**
(i) Type of Excitation.
(ii) Maximum Field Voltage.
(iii) Minimum Field Voltage.
(iv) Rated Field Voltage.
(v) Details of excitation loop in block diagrams showing transfer functions of individual elements using IEEE symbols.
(vi) Dynamic characteristics of over excitation limiter.
(vii) Dynamic characteristics of under excitation limiter.

**B.1.1.6 Parameters of Governor:**
(i) Governor average gain (MW/ Hz).
(ii) Speeder motor setting range.
(iii) Time constant of steam or fuel Governor Valve.
(iv) Governor valve opening limits.
(v) Governor valve rate limits.
(vi) Time constant of Turbine.
(vii) Governor block diagram showing transfer functions of individual elements using IEEE symbols.
B.1.1.7 Operational parameters:

Minimum notice time will be required to synchronize a Generating Unit from de-synchronization.

(i) Minimum time between synchronizing different Generating Units in the Power Station.

(ii) The minimum block load requirements on synchronizing.

(iii) Time required for synchronizing a Generating Unit for Hot/ Warm/ Cold conditions.

(iv) Maximum Generating Unit loading rating for Hot/ Warm/ Cold conditions.

(v) Minimum load without oil support (MW)

B.1.1.8 General Status

(i) Detailed Project report.

(ii) Status Report

- Land
- Coal
- Water
- Environmental clearance
- Rehabilitation of displaced persons

(iii) Techno-economic approval by Central Electricity Authority (CEA).

(iv) Approval of State Government/ Government of India.

(v) Financial Tie-up.

B.1.1.9 Connectivity

(i) Reports of Studies for parallel operation with the State Transmission System.

(ii) Short Circuit studies

(iii) Stability Studies.

(iv) Load Flow Studies.

(v) Proposed Connection with the State Transmission System.

- Voltage
- No. of circuits
- Point of Connection.
B.1.2 SGS Hydro Electric Stations

B.1.2.1 General

(i) Name of Power Station.
(ii) No. and capacity of units. (MW/ MVA)
(iii) Ratings of all major equipment.
   a. Turbines (HP)
   b. Generators (MVA)
   c. Generator Transformers (MVA)
   d. Auxiliary Transformers (MVA)
(iv) Single line diagram of Power Station and Switchyard.
(v) Relaying and metering diagram.
(vi) Neutral grounding of Generator.
(vii) Excitation control.
(viii) Earthing arrangements with earth resistance values
(ix) Reservoir Data.
   a. Salient features
   b. Type of Reservoir – Multipurpose/ Power
   c. Operating Table with;
      • Area capacity curves and
      • Unit capability at different net heads

B.1.2.2 Protection

(i) Full description including settings for all relays and protection systems installed on the Generating Unit, Generator transformer, auxiliary transformer and electrical motors of major equipments included.
(ii) Full description including settings for all relays installed on all outgoing feeders from Power Station switchyard, tie breakers, and incoming breakers.
(iii) Full description of inter-tripping of breakers at the point or points of Connection with the Transmission System.
(iv) Most Probable fault clearance time for electrical faults on the User's System.
B.1.2.3 Switchyard

(i) Interconnecting transformers:
- Rated MVA
- Voltage Ratio
- Vector Group
- Positive sequence reactance for max., min. and normal Tap(% on MVA)
- Positive sequence resistance for max., min. and normal Tap(% on MVA)
- Zero sequence reactance (% on MVA)
- Tap changer range (+ % to - %) and steps
- Type of Tap changer (off/ on load)
- Neutral grounding details.

(ii) Switchgear (including circuit breakers, Isolators on all circuits connected to the points of Connection).
- Rated voltage (kV).
- Type of Breaker (MOCB/ ABCB/ SF6).
- Rated short circuit breaking current (kA) 3 phase.
- Rated short circuit breaking current (kA) 1 phase.
- Rated short circuit making current (kA) 3 phase.
- Rated short circuit making current (kA) 1 phase.
- Provisions of auto reclosing with details.

(iii) Lightning Arresters
Number and location (line / transformer) with Technical data.

(iv) Communication System
Details of Communications equipment installed at points of connections.

(v) Basic Insulation Level (kV)
- Bus bar.
- Switchgear.
- Transformer Bushings
- Transformer windings

B.1.2.4 Generating Units:

(i) Parameters of Generator
- Rated terminal voltage (kV).
- Rated MVA.
- Rated MW
- Speed (rpm) or number of poles.
- Inertia constant H (MW sec. /MVA).
- Short circuit ratio.
- Direct axis synchronous reactance Xd (% on MVA).
- Direct axis (saturated) transient reactance (% on MVA) X'd.
- Direct axis (saturated) sub-transient reactance (% on MVA) X''d.
- Quadrature axis synchronous reactance (% on MVA) Xq.
- Quadrature axis (saturated) transient reactance (% on MVA) X'q.
- Quadrature axis (saturated) sub-transient reactance (% on MVA) X''q.
- Direct axis transient open circuit time constant (sec) T'do.
- Direct axis sub-transient open circuit time constant (sec) T''do.
- Quadrature axis transient open circuit time constant (sec) T'qo.
- Quadrature axis transient open circuit time content (sec) T''qo.
- Stator Resistance (Ohm) Ra.
- Stator leakage reactance (Ohm) X1.
- Stator time constant (sec).
- Rated Field current (A).
- Neutral grounding details.
- Open Circuit saturation characteristics of the Generator for various terminal voltages giving the compounding current to achieve this.
- Type of Turbine.
- Operating Head (Metres)
- Discharge with full gate opening (cumecs)
- Speed Rise on total Load throw off (%).
- MW and MVAR Capability curve

(ii) Parameters of excitation control system:
(iii) Parameters of governor:
(iv) Operational parameter:
  - Minimum notice required to synchronize a Generating Unit from de-synchronization.
  - Minimum time between synchronizing different Generating Units in a Power Station.
  - Minimum block load requirements on Synchronizing

B.1.2.5 General Status:

(i) Detailed Project Report.
(ii) Status Report.
  - Topographical survey
  - Geological survey
  - Land
- Environmental Clearance
- Rehabilitation of displaced persons.

(iii) Techno-economic approval by Central Electricity Authority.
(iv) Approval of State Government/ Government of India.
(v) Financial Tie-up.

B.1.2.6 Connectivity

(i) Reports of Studies for parallel operation with State Transmission System.
   - Short Circuit studies
   - Stability Studies.
   - Load Flow Studies.

(ii) Proposed Connection with the State Transmission System.
   - Voltage
   - No. of circuits
   - Point of Connection

B.1.2.7 Reservoir Data

(i) Dead Capacity
(ii) Live Capacity

---

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B.2 - DETAILED PLANNING DATA (Transmission)

B.2.1 General

(i) **Single line diagram** of the Transmission System down to 66kV,33kV bus at the Grid Substation detailing:

- Name of Substation.
- Power Stations connected.
- Number and length of circuits.
- Interconnecting transformers.
- Substation bus layout.
- Power transformers.
- Reactive compensation equipment.

(ii) **Substation layout** diagrams showing:

- Bus bar layout.
- Electrical circuitry, lines, cables, transformers, switchgear etc.
- Phasing arrangements.
- Earthing arrangements.
- Switching facilities and interlocking arrangements.
- Operating voltages.
- Numbering and nomenclature:
  - Transformers.
  - Circuits.
  - Circuit breakers.
  - Isolating switches

B.2.2 **Line Parameters** (for all circuits)

(i) **Designation of Line**

- Length of line (km).
- Number of circuits and Per Circuit values.
- Operating voltage (kV).
- Positive Phase sequence reactance (pu on 100 MVA) X1
- Positive Phase sequence resistance (pu on 100 MVA) R1
- Positive Phase sequence susceptance (pu on 100 MVA) B1
- Zero Phase sequence reactance (pu on 100 MVA) X0
- Zero Phase sequence resistance (pu on 100 MVA) R0
- Zero Phase sequence susceptance (pu on 100 MVA) B0
B.2.3 Transformer Parameters (for all transformers)

(i) Rated MVA
(ii) Voltage Ratio
(iii) Vector Group
(iv) Positive sequence reactance, max, min. and normal (pu on 100 MVA) X1
(v) Positive sequence resistance, max, min and normal (pu on 100 MVA) R1
(vi) Zero sequence reactance (pu on 100 MVA)
(vii) Tap change range (+ % to - %) and steps
(viii) Details of Tap changer (Off/ On load)

B.2.4 Equipment Details (For all substations)

(i) Circuit Breakers
(ii) Isolating switches
(iii) Current Transformers
(iv) Potential Transformers /CVTs

B.2.5 Relaying and Metering

(i) Protection relays installed for all transformers and feeders along with their settings and level of co-ordination with other Users.
(ii) Metering Details

B.2.6 System Studies

(i) Load Flow studies (Peak and lean load for maximum hydro and maximum thermal generation).
(ii) Transient stability studies for three-phase fault in critical lines.
(iii) Dynamic Stability Studies
(iv) Short circuit studies (three-phase and single phase to earth)
(v) Transmission Losses in the Transmission System.

B.2.7 Demand Data (For all substations)

Demand Profile (Peak and lean load).

B.2.8 Reactive Compensation Equipment

(i) Type of equipment (fixed or variable).
(ii) Capacities and/or Inductive rating or its operating range in MVAR.
(iii) Details of control.
(iv) Point of Connection to the System.
B.3 DETAILED PLANNING DATA (Distribution)

B.3.1 General

(i) Distribution maps (to scale) showing all lines up to 11kV and substations belonging to the supplier.

(ii) Single line diagram of Distribution System (showing distribution lines from points of Connection with the Transmission System, 66/11kV substations, 33/11kV substations, 11/0.4kV substation, Consumer bus in case of consumers fed directly from the Transmission System).

(iii) Numbering and nomenclature of lines and substations (Identified with feeding Grid substations of the Transmission and concerned 66/11kV substation, 33/11kV substation of Licensee).

B.3.2 Connection

(i) Points of Connection (Furnish details of existing arrangement of Connection).

(ii) Details of metering at points of Connection.

B.3.3 Loads

(i) Connected load - Active and Reactive Load. (furnish consumer details, Number of Consumers category wise, details of loads 1 MW and above, power factor etc.).

(ii) Information on diversity of load and coincidence factor.

(iii) Daily demand profile (current and forecast) on each 66/11kV substation and 33/11kV substation.

(iv) Cumulative demand profile of Distribution System (current and forecast).

(v) Demand mix of essential load (priority wise) and non essential loads in MW.

---
APPENDIX C- OPERATIONAL PLANNING DATA

C.1 OUTAGE PLANNING DATA

C.1.1 Demand Estimates (For Distribution Licensees)

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated aggregate month-wise annual sales of Energy in Million Units and peak and lean demand in MW and MVAR at each Connection point for the next financial year.</td>
<td>1st October of current year</td>
</tr>
<tr>
<td>Estimated aggregate day-wise monthly sales of Energy in Million Units and peak and lean demand in MW and MVAR at each Connection point for the next month.</td>
<td>25th of current month</td>
</tr>
<tr>
<td>15 Minute block-wise demand estimates for the day ahead.</td>
<td>10am every day</td>
</tr>
</tbody>
</table>

C.1.2 Estimates of Load Shedding (For Distribution Licensee)

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Details of discrete load blocks that may be shed to comply with instructions issued by SLDC when required, from each Connection point</td>
<td>Soon after Connection is made</td>
</tr>
</tbody>
</table>

C.1.3 Year Ahead Outage Programme (for the financial year)

C.1.3.1 SGS Generation Outage Programme

<table>
<thead>
<tr>
<th>Station Name</th>
<th>Date of BLR (for thermal)</th>
<th>Unit No.</th>
<th>Capacity (MW)</th>
<th>Proposed schedule</th>
<th>Reason</th>
<th>Total no. of maintenance days during previous year and date of Annual/capital maintenance</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
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</tbody>
</table>

Due date / Time for SGS- 1st October each year.
C.1.3.2  STS Outage Programme

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>• MW, which will not be available as a result of Outage from Imports through external Connections.</td>
<td>1st October of each year</td>
</tr>
<tr>
<td>• Start-date and start-time and period of Outage.</td>
<td></td>
</tr>
</tbody>
</table>

C.1.3.3  CPP’s Outage Programme

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>MW, which will not be available as a result of Outage. Start-date and start time and period of Outage.</td>
<td>1st October of each year</td>
</tr>
</tbody>
</table>

C. 1.3.4  Distribution Licensee’s Outage Programme

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Loads in MW not available from any Connection point.</td>
<td>1st October of each year</td>
</tr>
<tr>
<td>• Identification of Connection point.</td>
<td></td>
</tr>
<tr>
<td>• Period of suspension of Drawal with start-date and time.</td>
<td></td>
</tr>
</tbody>
</table>

C. 1.3.5  STU’s Outage Programme to SLDC

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed outage programme for transmission lines, equipments and substations</td>
<td>1st October of each year</td>
</tr>
</tbody>
</table>

C.1.3.6  Overall LGBR and Outage Programme (to be provided by SLDC)

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Report on proposed LGBR and Outage Programme to SRPC.</td>
<td>31st Oct. of each year</td>
</tr>
<tr>
<td>Release of finally agreed LGBR and Outage plan</td>
<td>31st Dec. of each year</td>
</tr>
</tbody>
</table>
### C.2 - SGS Generation Scheduling Data

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Day ahead 15-minute block-wise MW/ MVAR availability (00.00 - 24.00 Hours) of SGS.</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Day ahead 15-minute block-wise MW import/ export from CPP's.</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Status of Generating Unit Excitation AVR in service (Yes/ No).</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Status of Generating Unit Speed Control System Governor in service (Yes/ No).</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Spinning reserve capability (MW).</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Backing down capability with/ without oil support (MW).</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Hydro reservoir levels and restrictions</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Generating Units 15-minute block wise summation outputs (MW)</td>
<td>10.00 am</td>
</tr>
<tr>
<td>Day ahead 15-minute block wise MW entitlements from CGS to be provided by SRLDC</td>
<td>10.00 am</td>
</tr>
</tbody>
</table>

### C.3 SGS Capability Data

<table>
<thead>
<tr>
<th>Item</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Generators and IPPs shall submit to STU up-to-date capability curves for all Generating Units.</td>
<td>On receipt of request from STU/ SLDC.</td>
</tr>
<tr>
<td>CPPs shall submit to STU net return capability that shall be available for Export/ Import from Transmission System</td>
<td></td>
</tr>
</tbody>
</table>

### C.4 SGS Response to Frequency Change

<table>
<thead>
<tr>
<th>Item</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Response in MW at different levels of loads ranging from minimum Generation to registered capacity for frequency changes resulting in full opening of governor valve</td>
<td>On receipt of request from STU/ SLDC.</td>
</tr>
<tr>
<td>Secondary response in MW to frequency changes</td>
<td>On receipt of request from STU/ SLDC.</td>
</tr>
</tbody>
</table>
### C.5 Monitoring of Generation

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>SGS shall provide 15-minute block-wise generation summation to SLDC.</td>
<td>Real time basis</td>
</tr>
<tr>
<td>CPPs shall provide 15-minute block-wise export/import MW to SLDC.</td>
<td>Real time basis</td>
</tr>
<tr>
<td>Logged readings of Generators to SLDC.</td>
<td>As required</td>
</tr>
<tr>
<td>Detailed report of Generating Unit tripping on monthly basis.</td>
<td>In the first week of the succeeding month</td>
</tr>
</tbody>
</table>

### C.6 Distribution Licensee Essential and Non-essential load data

<table>
<thead>
<tr>
<th>Item</th>
<th>Due date/ Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>Schedule of essential and non-essential loads on each Discrete load block for purposes of load shedding.</td>
<td>As soon as possible after Connection</td>
</tr>
</tbody>
</table>
APPENDIX D

SITE RESPONSIBILITY SCHEDULE

Name of Power Station / Substation:

Site Owner:
Site Manager:
Tel. Number:
E-mail id:

<table>
<thead>
<tr>
<th>Item of Plant/Apparatus</th>
<th>Plant Owner</th>
<th>Safety responsibility</th>
<th>Control responsibility</th>
<th>Operation responsibility</th>
<th>Maintenance responsibility</th>
<th>remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>110 KV Switchyard</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>All equipments including bus bars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feeders</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generating Units</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>


# APPENDIX E
## INTIMATION OF INCIDENT

Name of Organization: ____________________________ Date: ____________________________  
Site Manager: ____________________________ Tel. Number: ____________________________  
Tel. Number: ____________________________ Email.id: ____________________________

<table>
<thead>
<tr>
<th>Sl. No</th>
<th>Item</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Date and time of incident</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Location of incident</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Brief description of incident</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>System parameters before the incident (voltage, frequency, flows, generation etc.)</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Relay indications received and performance of protection</td>
<td></td>
</tr>
<tr>
<td>6</td>
<td>Details of damage to plant and equipments affected</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Supplies interrupted and duration, if applicable</td>
<td></td>
</tr>
<tr>
<td>8</td>
<td>Quantum of generation lost, if applicable</td>
<td></td>
</tr>
<tr>
<td>9</td>
<td>Alternate supply arrangements</td>
<td></td>
</tr>
<tr>
<td>10</td>
<td>Estimated time for return to service</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>Cause of incident</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Any other relevant information and remedial action taken</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>Recommendation for improvement and preventing repeat of the incident</td>
<td></td>
</tr>
<tr>
<td>14</td>
<td>Details of Reporting official</td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX F (a)
REQUISITION FOR PERMIT TO WORK (PTW)

Date: 
Time: 

I, Mr. /Ms …………………………… request permit to work on the following HT/ EHT line/ equipment;

HV/EHV Apparatus/ Line Identification :

Details of works to be carried out :

Estimated time required for completion:

Signature: ………… Name (Requesting Safety Coordinator): …………………
Designation: Tel.No:

Name (Official in-charge of crew): ……………………….
Designation: Tel.No:
--- --- ---

(For use in Substations from where permit to work will be issued)

(a) Permit To Work issued: Yes / No

(b) No. and date of issue : (Code No.):

(c) Time of issue :

(d) Remarks: See conditions overleaf and check list (Appendix Fb).

(e) Date and Time to return the PTW :
--- --- ---

Receipt of PTW

I have received confirmation from …………………. (Name of issuing Authorized shift in charge of station/ safety coordinator) at …………………… (location) that the safety precautions have been established and the instructions will not be issued at his location for their removal until this PTW is cancelled.

Name and Signature ………………………………………..

(Requesting Safety Coordinator) of in-charge of the crew at …………..
(Location) on ………………… (Date and time).

(PTO)
Conditions of PTW/ LCP

1. This permit is valid only for working in the feeder/ equipment mentioned herein and not in any other feeder/ equipment.

2. Only authorized persons are allowed to work on feeders/ equipment for which the permit has been issued.

3. Works as per requisition only should be carried out.

4. Before touching any part of the feeder/ equipment the same should be earthed at two points on either side through standard discharge rods connected with good earth. Temporary earthing may only be removed after completion of all the works and after all the men have come down from the feeder/ equipment.

5. Work should be so planned that the PTW/ LCP is returned before or at the time indicated. If unavoidable delay is anticipated, advance information should be given to the location from where the PTW/ Line Clear is issued.

6. Before return of the PTW, it should be ensured that all the men, materials, tools/ tackles etc., on the line have returned and reported that all temporary earths are removed. There should also be a check on the material, tools and plant issued for the work to ensure that nothing is left behind on the line or equipment.

7. Only authorized persons should return the PTW/ LCP.

8. In case the PTW cannot be returned in person, the same may be returned to the PTW Issuing Authority over telephone by naming the code words assigned and the telephone number which is used for naming the code words assigned. In case two or more different code words are issued to the two or more persons in whose favour the permit is given, those persons must jointly return the PTW by naming their own code words. The PTW Return will not be deemed to be accepted unless returned by all these persons.

9. The Line Clear issuing authority should go over the checklist of Line Clear Return before accepting it.

10. If Line clear is returned over telephone, the Line Clear return form duly filled and signed should be sent to the PTW issuing authority by post immediately for record.

11. Control person should keep all the required data of PTW issued and LCR received. He should monitor and keep specific note in the log sheet when more than one PTW are issued on same line/ equipment/bay along with code words.
APPENDIX F (b)

Check List for Permit to Work (PTW) and Line Clear Permit (LCP)

LCP No ........................................ Dated ......................................... Time .................................

Check List of the Line Clear Permit:

(a) Location name, for which line clear is issued:

(b) Reference and authority requisitioning Line Clear:
    (Indicate original PTW No. including suffix and prefix)

(c) Identity of HV Apparatus:

(d) Sources from which the line/equipment is charged:

(e) Number/ name of circuit breaker/ isolating switch
    Open at each of above sources:

(f) Whether disconnection of line at both ends confirmed:

(g) Whether line is earthed at both ends:

(h) Whether circuit breaker truck removed in case of
    Indoor switchgear controlling the feeder/equipment
    for which line clear is given:

(i) Whether fuses of control supply voltage of the circuit
    breaker/ isolating switches controlling the feeder/
    Equipment for which line clear is given are removed
    and kept under safe custody:

(j) Time of issue of Permit to Work and No.:

(k) Name of requesting safety coordinator on whom
    PTW is issued:

(l) Approximate time for returning PTW as ascertained
    from the requesting coordinator:

Name and Signature ..........................................................

(Issuing Safety Coordinator)

Designation ........................................................................

(PTO)
Line Clear Permit (LCP)

LCP No:........................

I, Mr. /Ms. .................. ................. (Issuing Safety Coordinator) do hereby issue permission to Mr. /Ms. .................. (Requesting Safety Coordinator) for carrying out works as per requisition No.................. date and time........

The EHV/ HV Line/ equipment herein described are declared safe.
The permission is subject to the conditions given in PTW.

Name and Signature..............................................

(Person issuing Line Clear Permit)

Designation.........................................................

---
APPENDIX F (c)

LINE CLEAR RETURN (LCR)/ PERMIT TO WORK RETURN (PWR)

LCR No…………………… Date…….. Time: ………..

I, Mr. /Ms. ……………………… hereby return the LCP No…………… Issued at ……………… (Date and time) for the following HT/ EHT Line/ Apparatus.

I declare that all the crew who were sent on work have been withdrawn, temporary earth(s) removed, all repair tools and materials checked and the feeders/ equipments mentioned below are safe to be energized.

(a) HV/EHV Apparatus/ Line Identification:

(b) Safety precaution no longer required:

(c) Isolation:
   [State locations and each point of isolation
   Indicating means by which isolation was achieved]

(d) Earthing:
   [State location at which earthing was established and identify each point of earthing]

(e) Details of work done:

Check list to be ticked off:

(a) Whether all men withdrawn : Yes / No

(b) Whether all temporary earth removed: Yes / No

(c) Whether materials, tools and plant used in the work have been checked : Yes / No

(d) Code No : 
   (If used when Line Clear is returned over phone)

Name and Signature……………………………………………………
(Requesting Safety Coordinator)
Designation……………………………………………………………..

Official In-charge of Crew …………………………… (Name and Designation)
APPENDIX G

Payment for Reactive Energy Exchanges on Lines Owned by Individual Entities

Case-1: Interconnecting line owned by Entity – A

Metering Point (M): Substation of Entity – B

Entity A  ←  M  →  Entity B

Case-2: Interconnecting line owned by Entity – B

Metering Point (M): Substation of Entity – A

Entity A  ←  M  →  Entity B

Entity B pays to Entity A for:
(i) Net VARh received from Entity A while voltage is below 97%, and
(ii) Net VARh supplied to Entity A while voltage is above 103%.

Note: Net VARh and net payment may be positive or negative.
**Case- 3:** Interconnecting line jointly owned by Entity – A and B

Metering Points (M): Substations of Entity A and Entity B

Net VARh exported from S/S-A, while voltage < 97% = $X_1$

Net VARh exported from S/S-A, while voltage > 103% = $X_2$

Net VARh imported at S/S-B, while voltage < 97% = $X_3$

Net VARh imported at S/S-B, while voltage > 103% = $X_4$

(iii) Entity B pays to Entity A for, $X_1$ or $X_3$, whichever is smaller in magnitude, and

(iv) Entity A pays to Entity B for, $X_2$ or $X_4$, whichever is smaller in magnitude.

Note:

1. Net VARh and net payment may be positive or negative.

2. In case $X_1$ is positive and $X_3$ is negative, or vice-versa, there would be no payment under (i) above.

3. In case $X_2$ is positive and $X_4$ is negative, or vice-versa, there would be no payment under (ii) above.
APPENDIX H

Recommended Methodology for Relay Settings of Uncompensated Transmission Lines

1. ZONE-1 Reach setting

Zone-1: To be set to cover 80% of protected line length.

Set Zero sequence compensation factor $K_N$ as $(Z_0 - Z_1) / 3Z_1$.

Where:

$Z_1$ = Positive sequence impedance of the protected line

$Z_0$ = Zero sequence impedance of the protected line

Note: With this setting, the relay may overreach when parallel circuit is open and grounded at both ends. This risk is considered acceptable.

2. ZONE-2 Reach setting

Zone-2: To be set to cover the next 20% of length of principal line section plus 50% of shorter adjacent line to take care of underreaching due to mutual coupling effect. Set $K_N$ as $(Z_0 - Z_1) / 3Z_1$.

Sometimes impedance so selected might enter the next voltage level. However, un-selectivity in the Zone-2 grading is generally not to be expected when in-feeds exist at the remote sub-station as they reduce the overreach considerably.

This holds good for majority of the cases, however, for certain cases, where in-feed from other feeder at the local bus is not significant, Zone-2 of remote end relay may see the fault at lower voltage level. Care has to be taken for all such cases by suitable time delay.

3. ZONE-3 Reach setting

Zone-3 distance protection can offer time-delayed remote backup protection for an adjacent transmission circuit. To achieve this, Zone-3 distance elements must be set according to the following criteria where possible:

Zone-3 is to be set to cover the next 20% of the length of principal line section plus 100% of longest adjacent line.

However, in such case where Zone-3 reach is set to enter into next lower voltage level, Zone-3 timing shall be coordinated with the back-up protection (Directional over current and earth fault relay) of power transformer. Where such coordination cannot be realized, it is recommended to carry out simulation studies for relay reach and time.
coordination and suitable solution may be devised. Some of the typical solution can be application of back up distance protection for power transformer, duplicated protection for downstream 220kV feeders or special protection scheme logic. Similar issues, if encountered for Zone-2 reach setting, should also be addressed in the above manner.

4. Resistive Reach setting

For phase to ground faults, resistive reach should be set to give maximum coverage considering fault resistance, arc resistance and tower footing resistance. It has been considered that ground fault would not be responsive to line loading.

For Zone-1 resistive reach, attention has to be given to any limitations indicated by manufacturer in respect of resistive setting vis-a-vis reactance setting to avoid overreach due to remote in-feed. It is recommended to study the impact of remote end in-feed for expected power flow and fault resistance on the extent of overreach. This is particularly important for short lines.

In case of phase to phase fault, resistive reach should be set to provide coverage against all types of anticipated phase to phase faults subject to check of possibility against load point encroachment considering minimum expected voltage and maximum load expected during short time emergency system condition.

It is recommended that all the distance relays should have quadrilateral/polygon characteristic. For relays having Mho characteristic, it is desirable to have load encroachment prevention characteristic or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a line during emergency system condition, following criteria may be considered for deciding load point encroachment:

- Maximum load current ($I_{\text{max}}$) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15 minutes rating of the transmission facility).

- Minimum voltage ($V_{\text{min}}$) to be considered as 0.85pu (85%).

Due to in-feeds, the apparent fault resistance seen by relay is several times the actual value. This should be kept in mind while arriving at resistive reach setting for Zone-2 and Zone-3.
5. ZONE-2 Timer setting

A Zone-2 timing of 0.35 seconds (considering LBB time of 200ms, CB open time of 60ms, resetting time of 30ms and safety margin of 60ms) is recommended. However, if a long line is followed by a short line, then a higher setting (typically 0.6sec.) may be adopted on long line to avoid indiscriminate tripping through Zone-2 operation on both lines.

For special cases, following shall be the guiding philosophy:

Since Zone-2 distance protection is set to overreach the circuit it is intended to protect, it will also be responsive to faults within adjacent power system circuit. For this reason the time delay for Zone–2 back-up protection must be set to coordinate with clearance of adjacent circuit faults, within reach, by the intended main protection or by breaker fail protection.

The following formula would be the basis for determining the minimum acceptable Zone-2 time setting:

\[ t_{Z2} > t_{MA} + t_{CB} + t_{Z2\,reset} + t_S, \]

where:

- \( t_{Z2} \) = Required Zone-2 time delay
- \( t_{MA} \) = Operating time of slowest adjacent circuit main protection or Circuit Local back-up for faults within Zone-2 reach
- \( t_{CB} \) = Associated adjacent circuit breaker clearance time
- \( t_{Z2\,reset} \) = Resetting time of Zone-2 impedance element with load current present
- \( t_S \) = Safety margin for tolerance (e.g. 50 to 100ms)

Unequal lengths of transmission circuit can make it difficult to meet the Zone-2 secondary reach setting criterion. In such cases it will be necessary to co-ordinate Zone-2 with longer time delay. The time \( t_{MA} \) in equation must be the adjacent circuit Zone-2 protection operating time.

6. ZONE-3 Timer setting

Zone-3 timer should be set so as to provide discrimination with the operating time of relays provided in subsequent sections with which Zone-3 reach of relay being set, overlaps. Typical recommended Zone-3 time is 0.8 to 1.0 second.

For Special cases, where co-ordination between long and short lines is required, following formula would be the basis for determining the minimum acceptable Zone-3 time setting:
\[ t_{Z3} > t_{MA} + t_{CB} + t_{Z3\text{ reset}} + t_S, \text{ where:} \]

\[ t_{Z3} = \text{Required Zone-3 time delay} \]

\[ t_{MA} = \text{Operating time of slowest adjacent circuit local back-up protection} \]

\[ t_{CB} = \text{Associated adjacent circuit breaker clearance time} \]

\[ t_{Z3\text{ reset}} = \text{Resetting time of Zone-3 impedance element with load current present} \]

\[ t_S = \text{Safety margin for tolerance [e.g. 50 to 100 milliseconds (ms)]} \]

7. **Load Impedance Encroachment**

With the extended Zone-3 reach settings, that may be required to address the many under reaching factors already considered, load impedance encroachment is a significant risk to long lines of an interconnected power system. Not only the minimum load impedance under expected modes of system operation be considered in risk assessment, but also the minimum impedance that might be sustained for seconds or minutes during abnormal or emergency system conditions. Failure to do so could jeopardize power system security.

Ideal solution to tackle load encroachment may be based on the use of blinders or by suitably setting the resistive reach of specially shaped impedance elements or by use of polygon type impedance elements.

It is recommended that all the distance relays should have quadrilateral/ polygon characteristic. For relays having Mho characteristics, it is desirable to have load encroachment prevention characteristics or a blinder.

In the absence of credible data regarding minimum voltage and maximum load expected for a feeder during emergency system condition, following criteria may be considered for deciding resistive reach/ blinder setting to prevent load point encroachment:

- Maximum load current \((I_{max})\) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the minimum of the bay equipment individual rating) whichever is lower. (Caution: The rating considered is approximately 15 minutes rating of the transmission facility).
- Minimum voltage \((V_{min})\) to be considered as 0.85pu (85%).
- For setting angle for load blinder, a value of 30 degree may be adequate in most cases.
For high resistive earth fault where impedance locus lies in the Blinder zone, fault clearance shall be provided by the back-up directional earth fault relay.

8. **ZONE-4 Substation Local Backup Protection Settings**

Zone-3 distance protection is usually targeted to provide only remote back-up protection. In such a case, the distance relay may be provided with an additional zone of reverse-looking protection (e.g. Zone-4) to offer substation local back-up protection. The criterion for setting Zone-4 reverse reach would be as under:

- The Zone-4 reverse reach must adequately cover expected levels of apparent bus bar fault resistance, when allowing for multiple in feeds from other circuits. For this reason, its resistive reach setting is to be kept identical to Zone-3 resistive reach setting.

With a reverse reach setting of less than the Zone-1 reach of distance protection for the shortest line connected to the local bus bar, the Zone-4 time delay would only need to co-ordinate with bus bar main protection fault clearance and with Zone-1 fault clearance for lines out of the same substation. For this reason this can be set according to the Zone-3 time.

9. **Use of System Studies to Analyze Distance Relay Behaviour**

Often during system disturbance conditions, due to tripping of one or more trunk lines, some lines get overloaded and the system voltage drops. During such conditions the backup distance elements may become susceptible to operation due to encroachment of impedance locus in to the distance relay characteristic.

While the ohmic characteristic of a distance relay is independent of voltage, the load is not generally constant-impedance. The apparent impedance presented to a distance relay, as the load voltage varies, will depend on the voltage characteristic of the load. If the low voltage situation resulted from the loss of one or more transmission lines or generating units, there may be a substantial change in the real and reactive power flow through the line in question. The combination of low voltage and worsened phase angle may cause a long set relay to operate undesirably either on steady state basis, or in response to recoverable swings related to the initiating event.

The apparent impedance seen by the relay is affected by in-feeds, mutual coupling and therefore the behavior of distance relay during various system condition needs to be studied wherever necessary to achieve proper relay coordination.

It is desirable and hence recommended that system studies are conducted using computer-aided tools to assess the security of
protection by finding out trajectory of impedance in various zones of distance relay under abnormal or emergency system condition on case-to-case basis particularly for critical lines/ corridors.

In addition, the settings must be fine tuned, simulating faults using Real Time Digital Simulator on case-to-case basis particularly for critical lines/ corridors.

Such facilities available at CPRI, POWERGRID or elsewhere in the country should be used for protection related studies.

10. **Directional Phase Over Current Protection**

Directional phase over current relays are still being used as back-up protection for 220kV transmission lines by many utilities. In view of time coordination issues and increased fault clearance time in the event of failure of main distance protection, it is recommended that for all 220kV lines also Main-1 and Main-2 protections similar to 400kV lines be provided.

11. **Directional Ground Over Current Protection (DEF) Settings**

Normally this protection is applied as a supplement to main protection when ground fault currents may be lower than the threshold of phase over current protection. It might also be applied as main protection for high resistance faults.

The ground over current threshold should be set to ensure detection of all ground faults, but above any continuous residual current under normal system operation. Continuous residual current may arise because of following:

- Unbalanced series impedances of untransposed transmission circuits.
- Unbalanced shunt capacitance of transmission circuits.
- Third harmonic current circulation.

Various types of directional elements may be employed to control operation of ground over current (zero sequence over current) protection response. The most common approach is to employ Phase angle difference between Zero sequence voltage and current, since the relaying signals can easily be derived by summing phase current signals and by summing phase voltage signals from a suitable voltage transformer.

However, this method is not suitable for some applications where transmission lines terminated at different substations, run partially in parallel. In such cases following type of directional control is recommended to be used for the directional earth fault relay:
Relative phase of negative sequence voltage and current;

To ensure proper coordination, operating time must be set according to following criteria:

The DEF protection should not operate when the circuit local backup protection of remote end clears a fault in an adjacent circuit i.e. DEF should be coordinated with the remote end LBB.

12. **Power Swing Blocking Function**

While the power-swing protection philosophy is simple, it is often difficult to implement it in a large power system because of the complexity of the system and the different operating conditions that must be studied. There are a number of options one can select in implementing power-swing protection in their system. Designing the power system protection to avoid or preclude cascade tripping is a requirement of modern day power system. Two possible options are listed below:

12.1. **Block all Zones except Zone-I**

This application applies a blocking signal to the higher impedance zones of distance relay and allows Zone 1 to trip if the swing enters its operating characteristic. Breaker application is also a consideration when tripping during a power swing. A subset of this application is to block the Zone 2 and higher impedance zones for a preset time (Unblock time delay) and allow a trip if the detection relays do not reset.

In this application, if the swing enters Zone 1, a trip is issued, assuming that the swing impedance entering the Zone-1 characteristic is indicative of loss of synchronism. However, a major disadvantage associated with this philosophy is that indiscriminate line tripping can take place, even for recoverable power swings and risk of damage to breaker.

12.2 **Block all Zones and Trip with Out of Step (OOS) Function**

This application applies a blocking signal to all distance relay zones and order tripping if the power swing is unstable using the OOS function (function built in modern distance relays or as a standalone relay). This application is the recommended approach since a controlled separation of the power system can be achieved at preselected network locations. Tripping after the swing is well past the 180 degree position is the recommended option from CB operation point of view.

Normally all relay are having Power swing Un-block timer which unblocks on very slow power swing condition (when impedance locus
stays within a zone for a long duration). Typically the Power swing un-blocking time setting is 2 sec.

However, on detection of a line fault, the relay has to be de-blocked.

12.3. **Placement of OOS trip Systems**

Out of step tripping protection (Standalone relay or built-in function of Main relay) shall be provided on all the selected lines. The locations where it is desired to split the system on out of step condition shall be decided based on system studies.

*The selection of network locations for placement of OOS systems can best be obtained through transient stability studies covering many possible operating conditions.*

*Till such studies are carried out and Out-of-Step protection is enabled on all identified lines, it is recommended to continue with the existing practice of Non-Blocking of Zone-I on Power Swing as mentioned under Option-12.1 above. However, it should be remembered that with this practice the line might trip for a recoverable swing and it is not good to breakers.*

*It is strongly recommended that, the required studies must be carried out at the earliest possible time (within a timeframe of one year) to exercise the option under para 12.2 and 12.3 above.*

13. **Line Over Voltage Protection**

**For 400kV Lines:**

Low set stage (Stage-I) may be set in the range of 110% - 112% (typically 110%) with a time delay of 5 sec. High set stage (Stage-II) may be set in the range 140%-150% with a time delay of 100ms.

**For 765kV Lines:**

Low set stage (Stage-I) may be set in the range of 106% - 109% (typically 108%) with a time delay of 5 sec. High set stage (Stage-II) may be set in the range 140% - 150% with a time delay of 100ms.

However, for over voltage Stage-I protection, a time grading of 1 to 3 seconds may be provided between overvoltage relays of double circuit lines. Grading on overvoltage tripping for various lines emanating from a station may be considered and same can be achieved using voltage as well as time grading. Longest timed delay should be checked with expected operating time of Over-fluxing relay of the transformer to ensure disconnection of line before tripping of transformer.
It is desirable to have Drop-off to pick-up ratio of overvoltage relay better than 97% (considering limitation of various manufacturers’ relays on this aspect).

14. **Line Differential Protection**
   - Many transmission lines are now having OPGW or separate optic fiber laid for the communication. Wherever such facilities are available, it is recommended to have the line differential protection as Main-I protection with distance protection as backup (built-in Main relay or standalone).
   - Main-II protection shall continue to be distance protection.
   - For cables and composite lines, line differential protection with built-in distance back up shall be applied as Main-I protection and distance relay as Main-II protection.
   - Auto-reclose shall be blocked for faults in the cables.

15. **Maintaining Operation of Power Station Auxiliary System of Nuclear Power Plants:**
Depression of power supply voltages for auxiliary plant in some generating stations may reduce the station output. Maintenance of full generation output may be a critical power system security factor. In the case of nuclear plant, auxiliary power supplies are also a major factor in providing full nuclear plant safety and security.

The potential loss of system generation or the potential challenges to nuclear plant safety systems may be factors which will dictate the longest acceptable clearance times for transmission circuit faults in the vicinity of a power station. This should be further taken up with utilities of nuclear plants and this and any other requirements should be understood and addressed.

16. **Coordination between System Study Group and Protection Engineers,**
For quite a few cases where system behavior issues are involved it is recommended that power system study group is associated with the protection engineers. For example power swing locus, out of step tripping locations, faults withstands capability, zone2 and zone3 overlap reach settings calculations are areas where system study group role is critical/ essential.
Recommended Methodology for Relay Settings of Series Compensated Transmission Lines

Following phenomenon associated with the protection of Series compensated lines require special attention:

1. Voltage and Current Inversion.-
   1.1. Voltage inversion on Series Compensated line:

   In this case the voltage at the relay point reverses its direction. This phenomenon is commonly called as voltage inversion. Voltage inversion causes false decision in conventional directional relays. Special measures must be taken in the distance relays to guard against this phenomenon.

   1.2. Current inversion on Series Compensation line:

   Fault current will lead source voltage by 90 degrees if $X_C > X_S + X_{L1}$
   Current inversion causes a false directional decision of distance relays (voltage memories do not help in this case). [Here $X_C$ is reactance of series capacitor, $X_S$ is source reactance and $X_{L1}$ is reactance of the line].

   Current inversion influences operation of distance relays and therefore they cannot be applied without additional logic for the protection of series compensated lines when possibility of current inversion exists. Performance of directional comparison protections, based on residual (zero sequence) and negative sequence currents are also affected by current inversion. It is therefore, recommended to check the possibility of current inversion through system studies at the planning stage itself.

2. Low Frequency Transients

Series capacitors introduce oscillations in current and voltage in the power system, which are not common in non-compensated systems. These oscillations have frequencies lower than the rated system frequency and may cause delayed increase of fault currents, delayed operation of spark gaps as well as delayed operation of protective relays.

Low frequency transients have in general no significant influence on operation of line current differential protection as well as on phase comparison protection. However, they may significantly influence the correct operation of distance protection in two ways:

   - They increase the operating time of distance protection, which may in turn influence negatively the system stability;
• They may cause overreaching of instantaneous distance protection zones and this way result in unnecessary tripping on series compensated lines.

It is recommended to reduce the reach setting by a safety factor (Ks) to take care of possible overreach due to low frequency oscillations.

3. MOV Influence and Apparent Impedance

Metal Oxide Varistors (MOV) are used for capacitor over-voltage protection. In contrast to spark gaps, MOVs carry current when the instantaneous voltage drop across the capacitor becomes higher than the protective voltage level in each half cycle. Extensive studies have been done by Bonneville Power Administration in USA to arrive at a non-linear equivalent circuit for a series connected capacitor using an MOV. The composite impedance depends on total fault current and protection factor kp, which is defined by equation:

\[ k_p = \frac{U_{\text{mov}}}{U_{\text{NC}}} \]

where; \( U_{\text{MOV}} \) is voltage at which MOV starts to conduct theoretically and \( U_{\text{NC}} \) is voltage across the series capacitor when carrying its rated nominal current.

This should be considered while relay setting.

4. Impact of SC on Protective Relays of Adjacent Lines

Voltage inversion is not limited only to the buses and to the relay points close to the series compensated line. It can spread deep into the network and this way influence the selection of protection devices (mostly distance relays) at remote ends of the lines adjacent to the series compensated circuit, and sometimes even deeper in the network. Estimation of their influence on performances of existing distance relays of adjacent lines must be studied. In the study, it is necessary to consider cases with higher fault resistances, for which spark gaps or MOVs on series capacitors will not conduct at all.

If voltage inversion is found to occur, it may be necessary to replace the existing distance relays in those lines with distance relays that are designed to guard against this phenomenon.

5. Multi Circuit Lines

Two parallel power lines both series compensated running close to each other and ending at the same busbar at both ends can cause some additional challenges for distance protection due to the zero sequence mutual impedance. The current reversal phenomenon can also raise problems from the protection point of view, particularly when the power
lines are relatively short and when permissive overreach schemes are used.

- **Influence of Zero Sequence Mutual Impedance:**

Zero sequence mutual impedance \( Z_{M0} \) will not significantly influence the operation of distance protection as long as both circuits are operating in parallel and all precautions related to settings of distance protection on series compensated line have been considered. Influence of parallel line switched off and earthed at both ends, on the operation of distance protection on single operating circuit is well known.

The presence of series capacitor additionally exaggerates the effect of zero sequence mutual impedance between two circuits. The effect of zero sequence mutual impedance on possible overreaching of distance relays is increased further compared to case of non-compensated lines. This is because while the series capacitor will compensate self-impedance of the zero sequence network the mutual impedance will be same as in the case of non-compensated double circuit lines. The reach of under reaching distance protection zone 1 for phase to earth measuring loops must further be reduced for such operating conditions.

Zero sequence mutual impedance may also disturb the correct operation of distance protection for external evolving faults during auto reclosing, when one circuit is disconnected in one phase and runs in parallel during dead time of single pole auto reclosing cycle. *It is recommended to study all such operating conditions by dynamic simulations in order to fine tune settings of distance relays.*

6. **Directional Residual Over Current Protection**

All basic application considerations, characteristic for directional residual over current protection on normal power lines apply also to series compensated lines with following additions. Low fault currents are characteristic of high resistive faults. This means that the fault currents may not be enough to cause voltage drops on series capacitors that would be sufficient to start their over voltage protection. Spark gaps may not flash over in most cases, and metal oxide Varistors (MOVs) may not conduct any significant current. Series capacitors may remain fully inserted during high resistive earth faults.

- **Local end directional residual OC protection:**

The directional relay operates always correctly for reverse faults. VT located between bus and capacitor generally does not influence directional measurement. But in case VT is located between line and capacitor it may influence correct operation. While reverse faults are detected correctly, the forward operation is dependent on system conditions. Additional zero sequence source impedance can be added into relay circuits to secure correct directional measurement.
Remote end directional residual OC protection:

In this case the current can be reduced to extremely low values due to low zero sequence impedance at capacitor end. Further the measured residual voltage can be reduced to very low value due to low zero sequence source impedance and/or low zero sequence current. Zero sequence current inversion may occur at the capacitor end (dependent on fault position). Directional negative sequence OC protection too may face very similar conditions.

Adaptive application of both the above OC protection principles can be considered wherever required to get the desired result.

7. Distance Protection Settings Guidelines

Basic criteria applied for Z1 and Z2 reach settings are:

- Zone-1 should never overreach for the fault at remote bus;
- Zone-2 should never under reach for fault on protected line;
- **Permissive Over reach** (POR) schemes are usually applied.

Distance protection Zone 1 shall be set to;

Zone-1 is set usually at 80% of $K_s \times X_{Z1} \Box K_s \Box X_{11} \Box X_{12} \Box X_c$

where $X_{11}$ is reactance between CT and capacitor and $X_{12}$ is reactance between capacitor and remote end Bus,

$K_s$ is reactance of capacitor and

$K_s$ is safety factor to prevent possible overreaching due to low frequency (sub-harmonic) oscillations.

These setting guidelines are applicable when VT is installed on the bus side of the capacitor. It is possible to remove $X_c$ from the above equation in case VT is installed on line side, but it is still necessary to consider the safety factor.

- Alternatively, Zone-1 is set at 80% of line impedance with a time delay of **100 milli second**. POR Communication scheme logic is modified such that relay trips instantaneously in Zone-1 on carrier receive. (For remote end relay of the line looking into series capacitor).

- Zone-2 is set to 120 % of uncompensated line impedance for single circuit line. For double circuit lines, special considerations are mentioned at Clause 5 of this Appendix.
• Phase locked voltage memory is used to cope with the voltage inversion. Alternatively, an intentional time delay may be applied to overcome directionality problems related to voltage inversion.

• Special consideration may be required in over voltage stage-I (low set) trip setting for series compensated double circuit lines. It has been experienced that in case of tripping of a heavily loaded circuit, other circuit experience sudden voltage rise due to load transfer. To prevent tripping of other circuit on such cases, over-voltage stage-I setting for series compensated double circuit lines may be kept higher at 113%.

8. Simulation Studies

System studies, Use of real Time digital simulators, Tests using EMTP files are very important when applying protections for series compensated lines. It is recommended to carry out such studies specific to each line.
APPENDIX – J

General Information of Substations to be provided Annually for Protection Audit

Name of Substation : 
Date of commissioning : 
Type of Bus Switching Scheme: 
SLD of the Station attached : 

Details

1. Instrument Transformers (CT and CVT)
   a) Location / Make / Rating : 
   b) Date of Testing 
   c) No. of Cores 
   d) Ratio adopted and measured Core wise 
   e) Error calculated “
   f) Knee point voltage (for CT) “

2. Protection System Availability
   a) Busbar Relay (Voltage wise)
      i) Make and Model : 
      ii) Stability Checks / date of testing : 
      iii) Remarks : 
   b) Substation Protection and Monitoring equipments (Voltage wise)
      With Make and Model, Functional status and date of last Testing for:
      i) LBB 
      ii) Event Logger 
      iii) Synchronizing facility availability 
      iv) Synchro check relay and Setting 
   c) Transmission Line Protection (Line wise)
      Name of Line, Relay Make and Model, Functional status and Date of testing for
      i) Main I Protection 
      ii) Main II Protection 
      iii) LBB Protection 
      iv) PLCC/ Protection Coupler 
      v) DR 
      vi) Time Synch. Unit 

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d) **Transformer Protection**
Name of ICTs with Rating, Make and Model of Relays, LA etc.:

1. Differential protection
2. REF protection
3. Back up Over Current Protection
4. Over Flux Protection
5. Other protections
6. Bucholtz / PRD
7. LA rating (HV and LV)
8. OTI / WTI Indication working status
9. Date of last Testing.

e) **Reactor Protection**
Name of Line / Bus reactor, Protection Relay make and model of:

1. Differential protection
2. REF Protection
3. Back up over Impedance Protection
4. Over flux Protection
5. Other protections
6. Bucholtz/ PRD
7. LA (HV side)
8. OTI/ WTI indication working status
9. Date of last Testing.

3. **Transmission line parameters** (Line wise)

   a. Name of line and length (km)
   b. Line parameters (in Ohms/ km/ phase – primary value)

   R1
   X1
   R0
   X0
   R0M
   X0M

   c. Relay setting (Adopted and Recommended)
   (Provide settings of all lines, transformers/ reactors and bus bars).
4. DC Supply

Availability of:
- 220V (DC I and II)
- 110V (DC I and II)
- 48 V (DC I and II)
- Battery chargers

No. of Cells per Battery bank

Voltage measured at farthest Panel for:
- Positive to Earth
- Negative to Earth

5. Circuit Breakers

Provide details Bay wise for each Voltage level;

a) Make and Model
b) Breaker status indicator availability
c) No. of Trip / Close coils and its healthiness
d) Availability of PIR
e) Date of last Operation timing taken
f) Remarks

6. Availability of Auxiliary Supply

a) Auxiliary Supply I and II with;
   Source of supply, Reliability and Average tripping per month.

b) DG Set I and II with;
   Make, Rating, Auto / Manual, Fuel level etc.

7. Availability of UFR and df/dt relays

Make and Setting

8. Availability of Special Protection Scheme (SPS)

Available : (Yes/ No)
Verification status:

9. Tripping Analysis and Status of corrective actions taken

10. Any other Major Comments / Observations.