ANNEXURE D2

1. Definitions of Protection System, its Philosophy and aspects related to Protection Coordination

1.1 Definitions:

a) Act

The Electricity Act, 2003 as amended from time to time.

b) Auto recloser

A circuit breaker equipped with a mechanism that can automatically close the breaker after it has been opened due to a fault.

c) Contingency

The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

d) Corrective Action Plan

A list of actions and an associated timetable for implementation to remedy a specific problem.

e) Central Transmission Utility (CTU)

Any Government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act;

f) Dead time of auto recloser relay

The time between the auto-reclose scheme being energized and the completion of the circuit to the circuit breaker closing contactor.

g) Disturbance

- An unplanned event that produces an abnormal system condition.
- Any perturbation to the electric system.
- The unexpected change in Area Control Error (ACE) that is caused by the sudden failure of generation or
- Interruption of load.

h) Disturbance Recorder (DR)

A device provided to record the behaviour of the pre-selected digital and analog values of the system parameters during an Event.

i) Entity

A Generating Company including captive generating plant or a transmission licensee including Central Transmission Utility and State Transmission Utility or a distribution licensee or a Bulk Consumer whose electrical plant is connected to the Grid at voltage level 33 kV and above.

j) Event Logger(EL)

A device provided to record the chronological sequence of operations, of the relays and other equipment.

k) Facility
A set of electrical equipment that operates as a single Grid Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

l) Facility Rating
The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

m) Generating Company
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.

n) Grid
The entire inter-connected electric power network of the country.

o) Grid disturbance
Tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, resulting in total failure of supply at a sub-station or loss of integrity of the grid, at the level of transmission system at 220 kV and above (132 kV and above in the case of North-Eastern Region).

p) Grid incident
Tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 220 kV and above (132 kV and above in the case of North-Eastern Region).

q) Grid Standards
The standards specified by the Authority under clause (d) of the Section 73 of the Act.

r) Indian Electricity Grid Code (IEGC) or Grid Code
These regulations specifying the philosophy and the responsibilities for planning and operation of Indian power system.

s) Interconnection
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control.

t) Inter State Transmission System (ISTS)

- Any system for the conveyance of electricity by means of a main transmission line from the territory of one State to another State.
- The conveyance of electricity across the territory of an intervening State as well as conveyance within the State which is incidental to such inter-state transmission of energy.
- The transmission of electricity within the territory of State on a system built, owned, operated, maintained or controlled by CTU.

u) Load Blinder

Load blinders are the load encroachment elements used to block the distance relay when there is heavy load in the system to avoid cascading trips in the network.

v) NLDC

The Centre established under sub-section (1) of Section 26 of the Act.

w) Power System

All aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely.

- generating stations;
- transmission or main
- transmission lines;
- sub-stations;
- tie-lines;
- load despatch activities;
- mains or distribution mains;
- electric supply lines;
- overhead lines;
- service lines;
- works.

x) Reactor

An electrical facility specifically designed to absorb Reactive Power.

y) Reclaim time of auto-reclose relay

The time from the making of the closing contacts on the auto-reclose relay to the completion of another circuit within the auto-reclose scheme which will reset the scheme or lock out the scheme or circuit breaker as required.

z) Regional Power Committee (RPC)

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.

aa) Regional Load Despatch Centre (RLDC)

The Centre established under sub-section (1) of Section 27 of the Act.

bb) State Load Despatch Centre (SLDC)
The Centre established under subsection (1) of Section 31 of the Act.

cc) Special Protection Scheme
A scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation (MW and MVAR), tripping load, or reconfiguring a System(s).

dd) Stability Limit
The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.

ee) State Transmission Utility (STU)
The Board or the Government Company specified as such by the State Government under sub-section (1) of Section 39 of the Act.

ff) Thermal Rating
The maximum amount of electrical current that a transmission line or electrical facility can
conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.

gg) Transient stability
The ability of the power system to maintain synchronism when subjected to a severe disturbance such as a short circuit on a transmission line.

hh) Transmission License
A License granted under Section 14 of the Act to transmit electricity.

ii) Transmission Planning Criteria
The policy, standards and guidelines issued by the CEA for the planning and design of the Transmission system.

jj) Trickle/ Boost charging of battery
Trickle charging means charging a fully charged battery under no-load at a rate equal to its self-discharge rate, thus enabling the battery to remain at its fully charged level. A battery under continuous float voltage charging is said to be under float-charging. Boost charging means charging a discharged battery at a high current for short period of time. Boost charge enables the quick charging of depleted batteries.

Words and expressions used and not defined in these standards but defined in the Act shall have the meaning assigned to them in the Act.

1.2 General Philosophy of Protection System:

There shall be protection philosophy which shall be prepared and adopted by each RPC in coordination with stakeholders in the concerned region in accordance with below mentioned objectives, design criteria and other details. However, protection design in a particular system may vary depending upon judgment and experience in the broad contours of above protection philosophy. Consideration must also be given to the type of equipment to be protected as well as the importance of this equipment to the system. Further, protection must not be defeated by the failure of a single component:

1.2.1 Objectives:

The basic objectives of any protection schemes should be to:

(i) Mitigate the effect of short circuit and other abnormal conditions in minimum possible time and area.

(ii) Indicate the location and type of fault and

(iii)Provide effective tools to analyze the fault and decide remedial measures.

1.2.2 Design Criteria: To accomplish the above objectives, the four design criteria for protection that should be considered are: (i) fault clearing time; (ii)selectivity; (iii)sensitivity and (iv) reliability (dependability and security).

1.2.2.1 Fault clearing time: In order to minimize the effect on customers and maintain system stability, fault clearing time shall be as per CEA Grid Standard Regulations 2010.

1.2.2.2 Selectivity: To ensure Selectivity, coordination shall be ensured with the adjacent protection schemes including breaker failure, transformer downstream relays, generator protection and station auxiliary protection.

1.2.2.3 Sensitivity: To ensure Sensitivity, the settings must be investigated to determine that they will perform correctly for the minimum fault current envisaged in the system, yet remain stable during transients and power swings from which the system can recover.

1.2.2.4 Reliability: To ensure Reliability, two independent auxiliary direct current-supplies shall be provided for Main-I and Main-II relays. The Main-I and Main-II relays should be from two different makes or operating with different algorithm. The CB´s shall have two independent trip coils and two independent trip circuits. Each protection device should trip at least one of them by independent auxiliary DC- supplies.

1.2.2.5 Security: To ensure Security, the protection shouldn’t limit the maximum transmission capacity of the element. Distance protection in particular could cause spurious tripping due to specific grid conditions, in case of high load operation. Therefore, any special topologies must be known and considered for protection parameterization. For parallel Over Head Lines it is necessary to consider the rapid increase of load current in the healthy line when the faulty line trips and the protection operation must allow such conditions The load encroachment detection function of the relays must be used, when the highest distance zone resistance reach conflicts with the maximum transmitted load on the protected element.

1.3 Philosophy of Line Protection:

Transmission circuit construction can be considered in three main categories viz.: Overhead construction, Underground cable construction and Composite (overhead plus underground) construction. The requirements of overhead line and cable protection systems vary greatly, due to the exposure of transmission circuits to a wide variety of environmental hazards and are subjected to the wide variations in the format, usage and construction methodologies of transmission circuits. The type of protection signaling (tele- protection) or data communication systems required to work with the protection systems will also influence protection scheme requirements.

Transmission circuit Main protection is required to provide primary protection for the line and clear all type of faults on it within shortest possible time with reliability, selectivity and sensitivity. Transmission circuit back-up protection shall cater for failure of any main protection system to clear any fault that it is expected to clear. A protection function that offers back-up for most faults may also provide main protection for some fault conditions. Combinations of main and back-up protection systems should be used to address the main and application specific requirements for transmission circuits.

1.3.1 Design Criterions: While designing the scheme for protection of transmission lines following criteria shall be included:

(i) The systems applied must be capable of detecting all types of faults, including maximum expected arc resistance that may occur at any location on the protected line.

(ii) The protection should be set not to trip under system transient conditions, which are not short circuits. Conversely where the short circuit current is low due to local grid conditions (weak network) or due to high resistance of the arc, this must be taken into consideration to trip the relay by using the most appropriate criterion, without jeopardizing the unwanted tripping during heavy load conditions. Protection relays must allow the maximum possible loadability of the protected equipment, while ensuring the clearing of anticipated faults according to the simulation studies.

(iii) The design and settings of the transmission line protection systems must be such that, with high probability, operation will not occur for faults external to the line or under non-fault conditions.

(iv) Settings related to the maximum possible loadability of the protected equipment shall be specified after a suitable load flow study and contingency analysis.

1.3.2 Reliability Criterions:

A. For transmission line having voltages at 220kV and above: High speed Duplicated Main Protection (Main-I and Main-II) shall be provided and at least one of them being carrier aided non-switched four zone distance protection. The other protection may be a phase segregated current differential (this may require digital communication) or a carrier aided non-switched distance protection.

Wherever Optical Ground Wire (OPGW) or separate optic fibre laid for the Communication is available, Main-I and Main-II protection shall be the line differential protection with distance protection as backup (builtin Main relay or standalone). For very short line (less than 10 km), line differential protection with distance protection as backup (built-in Main relay or standalone) shall be provided mandatorily as Main-I and Main-II.).

In addition to above, following shall also be provided:

(i) Two stage over-voltage protection. However, in case of 220 kV lines, in cases where system has grown sufficiently or in case of short lines, utilities on their discretion may decide not to provide this protection.
(ii) Auto reclose relay suitable for 1 ph or 3 ph (with deadline charging and synchro- check facility) reclosure.
(iii) Sensitive Inverse Definite Minimum Time (IDMT) directional E/F relay (standalone or as built-in function of Main-I & Main-II relay).

Main Protection shall have following features:

a. The Main-I and Main-II protection shall be numerical relays of different makes or employ different fault detection algorithm.
b. Each distance relay shall protect four independent zones (three forward zones and one reverse zone). It shall be provided with carrier aided tripping.
c. The relays should have sufficient speed so that they will provide the clearing times as defined in the latest revision of CEA Grid Standards Regulations.
d. The Main-I and Main-II relays shall be powered by two separate DC source.
e. Both, Main-I and Main-II shall send separate initiation signal to Breaker Failure Relay.
f. Internal Directional Earth Fault function shall be set to trip the line in case of high resistance earth faults.
g. The Broken Conductor detection shall be used for alarm purpose only.
h. The internal overvoltage function shall be used to protect the line against over voltages. The protection shall be set in two stages. The lines emanating from same substation shall be provided with pick-up as well as time grading to avoid concurrent trippings. The overvoltage relay shall have better than 97% drop-off to pick-up ratio (the ratio of the limiting values of the characteristic quantity at which the relay resets and operates).

B. For transmission line having voltages at 132kV: There should be at least one carrier aided non-switched four zone distance protection scheme. In addition to this, another non-switched/switched distance scheme or directional over current and earth fault relays should be provided as back up. Main protection should be suitable for single and three phase tripping. Additionally, auto-reclose relay suitable for 1 ph or3 ph (with dead line charging and synchro-check facility) reclosure shall be provided. In case of both line protections being Distance Protections, IDMT type Directional E/F relay (standalone or as built-in function of Main-I & Main-II relay) shall also be provided additionally.

1.3.3 Following types of protection scheme may be adopted to deal with faults on the lines:

1.3.3.1. Distance Protection scheme: The scheme shall be based on the measuring the impedance parameters of the lines with basic requirements as below:

a. Each distance relay shall protect four independent zones (three forward zones and one reverse zone). It shall be provided with carrier aided tripping.

b. Each Distance Relay:

  i. Shall include power swing detection feature for selectively blocking, as required.
  ii. Shall include suitable fuse-failure protection to monitor all types of fuse failure and block the protection.
  iii. Shall include load encroachment prevention feature like Load blinder.
  iv. Shall include Out of Step trip function.
  v. Distance relay as Main protection should always be complemented by Directional ground protection to provide protection for high resistive line faults.
  vi. Shall be capable to protect the series compensated lines from voltage inversion, current inversion phenomenon. Special measures must be taken to guard against these phenomenon.

1.3.3.2 Line Differential Protection: The scheme shall be based on the comparing the electrical quantities between input and output of the protected system. Provided that:

(a) Due to the fact that short lines and/or cables do not have enough electrical length, the current differential relay should always be used.

(b) For Cables, at least a differential line protection shall be used in order to guarantee fast fault clearing while maintaining security. The reason being that there are many sources of errors associated to other protection principles, especially for ground faults in cables.

The differential protection shall have following requirements:

(i) Line differential as Main-I with inbuilt Distance Protection shall be installed for all the lines irrespective of length (subject to technical limitations). The inbuilt distance protection feature shall get automatically enabled in case of communication failure observed by the differential relay.

(ii) The differential relays provided in 220kV and above system must operate in less than 30 ms.

(iii) The current differential protection should a reliable type (preferably digital). The protection should be of the segregate phase type, i.e. it should be able to detect the phase in fault and therefore for the case of single line-ground (SLG) faults to trip only the phase in fault (also to establish single phase A/R). The synchronization of the measured values is done via a communication system. The communication system for differential line protection should be based on fiber optic and any equipment should comply with the IEC 60834.

1.3.4. Auto Reclosing:

The single phase high speed auto-reclosure (HSAR) at 220 kV level and above shall be implemented, including on lines emanating from generating stations. If 3-phase autoreclosure is adopted in the application of the same on lines emanating from generating stations should be studied and decision taken on case to case basis by respective RPC.

1.3.4.1 AR Function Requirements:

It shall have the following attributes:

(i) Have single phase or three phase reclosing facilities.
(ii) Have a continuously variable single phase dead time.
(iii) Have continuously variable three phase dead time for three phase reclosing.
(iv) Have continuously variable reclaim time.
(v) Incorporate a facility of selecting single phase/three phase/single and three phase auto-reclose and non-auto reclosure modes.
(vi) Have facilities for selecting check synchronizing or dead line charging features.
(vii) Be of high speed single shot type
(viii) Suitable relays for SC and DLC should be included in the overall auto-reclose scheme if three phase reclosing is provided.
(ix) Should allow sequential reclosing of breakers in one and half breaker or double breaker arrangement.

1.3.4.2. Scheme Special Requirements:

(i) Modern numerical relays (IEDs) have AR function as built-in feature. However, it is recommended to use standalone AR relay or AR function of Bay control unit (BCU) for 220kV and above voltage lines. For 132kV lines, AR functions built-in Main distance relay IED can be used.
(ii) Fast simultaneous tripping of the breakers at both ends of a faulty line is essential for successful auto-reclosing. Therefore, availability of protection signaling equipment is a pre-requisite.
(iii) Starting and Blocking of Auto-reclose Relays:
Some protections start auto-reclosing and others block. Protections which start A/R are Main-I and Main-II line protections. Protections which block A/R are:

a. Breaker Fail Relay
b. Line Reactor Protections
c. O/V Protection
d. Received Direct Transfer trip signals
e. Busbar Protection
f. Zone 2/3 of Distance Protection
g. Carrier Fail Conditions
h. Circuit Breaker Problems.

i. Phase to Phase Distance Trip

When a reclosing relay receives start and block A/R impulse simultaneously, block signal dominates. Similarly, if it receives ‘start’ for 1-phase fault immediately followed by multi- phase fault the later one dominates over the previous one.

1.3.4.3 Requirement for Multi breaker Arrangement:

Following schemes shall be adhered to multi-breaker arrangements of one and half breaker or double breaker arrangement:

(i) In a multi-Circuit Breaker (C.B.) arrangement one C.B. can be taken out of operation and the line still be kept in service. After a line fault only those C.Bs which were closed before the fault shall be reclosed.

(ii) In multi-C.B. arrangement it is desirable to have a priority arrangement so as to avoid closing of both the breakers in case of a permanent fault.

(iii) A natural priority is that the C.B. near the busbar is reclosed first. In case of faults on two lines on both sides of a tie C.B. the tie C.B. is reclosed after the outer C.Bs. The outer C.Bs. do not need a prioritizing with respect to each other.

(iv) In case of bus bar configuration arrangement having a transfer breaker, a separate auto- reclosure relay for transfer breaker is recommended.

1.3.4.4 Setting Criteria:

(i) Auto reclosing requires a dead time which exceeds the de-ionising time. The circuit voltage is the factor having the predominating influence on the de-ionising time. Single phase dead time of 1.0 sec. is recommended for 765 kV, 400 kV and 220 kV system. For the lines emanating from generating stations single-phase dead time upto 1.5 sec may be adopted.

(ii) According to IEC 62271-101, a breaker must be capable of withstanding the following operating cycle with full rated breaking current:

O - 0.3 s - CO - 3 min - CO

The recommended operating cycle at 765kV, 400 kV and 220 kV is as per the IEC standard. Therefore, reclaim time of 25 Sec. is recommended.

1.3.5. Power Swing Blocking and Out of Step (OOS) Function

Large interconnected systems are more susceptible to Power Swings in comparison to the erstwhile smaller standalone systems. Inter-area Power Swings can be set up even due to some event in far flung locations in the system. During the tenure of such swings, outage of any system element may aggravate the situation and can lead to instability (loss of synchronism). It is hence extremely important that unwanted tripping of transmission elements need to be prevented, under these conditions. Distance protection relays demand special consideration under such a situation, being susceptible to undesirable mis-operation during Power swings which may be recoverable or irrecoverable power swings. Following steps may be adopted to achieve above objective:

A. 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.

B. 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 relay is 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 2sec.

However, on detection of a line fault, the relay has to be de-blocked.

C. 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. Based on these system studies, either of the option above may be adopted after the approval of Appropriate Sub-Committee of RPC.

While applying Power Swing Blocking (PSB) in the distance protection relay a few other important aspects also needs to be considered.

- PSB function should not block if negative sequence or zero sequence currents are present. Once blocked, the PSB should unblock if negative sequence or zero sequence currents are detected. Power Swing is a balanced three phase phenomenon and unbalance can only occur in the case of an asymmetrical fault.
- It will be desirable that during tenure of PSB, the distance protection is capable of detecting a fault and tripping. If such a feature is not available in the relay, PSB should be unblocked after a time delay, corresponding to the half cycle period of the slowest expected Swing Frequency (usually 2s corresponding to the slowest swing frequency of 0.25Hz is considered as default), to avoid the protection remaining perpetually blocked.

1.4 Protection Coordination:

A protection-coordination study shall be done to determine the trip settings of each protective device in the power system so that maximum protection with minimum interruption is provided for all faults that may happen in the system. System studies shall be 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.

Relay coordination calculation module must consider the operating characteristics of the relays, normal operating and thermal or mechanical withstand characteristics of the equipment and must determine the optimum relay settings to achieve the protection objectives stated under Para 1.2.1.

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.

Part 1 (Requirements)

The purpose is to ensure system protection is coordinated among operating entities. The Protection coordination requirement shall include the following:

(1) Each Transmission Licensee, Load Dispatch Centre (LDC) and Generator Company shall keep themselves familiarized with the purpose and limitations of Protection System schemes applied in its area of control.

(2) Each Transmission licensee shall coordinate its Protection System schemes with concerned transmission system, sub-transmission system and generators.

(3) Each Generating Company shall coordinate its Protection System schemes with concerned transmission system and station auxiliaries.

(4) Each Transmission Licensee and Generation Company shall be responsible for settings calculations for protection of elements under its ownership. It shall be the responsibility of the respective asset owner to obtain the inputs (adjacent line settings, infeed values etc.) from CTU/STU/RPC necessary for calculation of the settings.

(5) CTU/STU shall provide the infeed values/latest network model to the requesting entity, within 15 days of receipt of such a request from the entity. The RPC shall provide the existing settings of the adjacent substations within 15 days of such a request from the requesting entity.

(6) Each Generating Company and Transmission Licensee shall submit the protection settings along with the calculation sheets, co-ordination study reports and input data, in advance, to respective RPC for every new element to be commissioned. The mentioned information shall be submitted to the RPC by first week of each month for all the elements proposed to be commissioned in the following month.

(7) The appropriate sub-committee of RPC shall review the settings to ensure that they are properly coordinated with adjacent system and comply with the existing guidelines. The onus to prove the correctness of the calculated settings shall lie with the respective Transmission licensee/Generation Company. In case, the sub-committee feels that the adjacent transmission system settings need to be changed, in view of the new element, it shall inform the concerned entity for revision of the existing settings.

(8) If the RPC feels the need, it may recommend carrying out the dynamic study for the concerned system to ensure that the present settings are sufficient for maintaining the dynamic stability of the system. In such a case, on being directed by RPC, the respective CTU/STU shall carry out the necessary dynamic studies and submit the report to the RPC.
(9) The appropriate sub-committee of RPC shall review and approve the settings based on the inputs/report submitted by the entities.
(10) The approved settings shall be implemented by the entity and proper record of the implemented settings shall be kept. The modern numerical relays have several settings for various features available in the relay. It shall be ensured that only the approved features and settings are enabled in the relay. No additional protection/setting shall be enabled without the prior approval by respective RPC.
(11) Each Transmission licensee and Generation Company shall co-ordinate the protection of its station auxiliaries to ensure that the auxiliaries are not interrupted during transient voltage decay.
(12) Any change in the existing protection settings shall be carried out only after prior approval from the RPC. The owner entity shall inform all the adjacent entities about the change being carried out.
(13) In case of failure of a protective relay or equipment failure, the Generator Company and Transmission Licensee shall inform appropriate LDC. The Generator Company and Transmission Licensee shall take corrective action as soon as possible.
(14) Each Transmission Licensee shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Company, Transmission Licensee, and appropriate LDC.
(15) Each Transmission Licensee, Generator Company and Distribution Licensee shall monitor the status of each System Protection Scheme in their area, and shall inform to concerned RLDC about each change in status.

Part 2 (Measures of Compliance)

The measures to be done for Protection coordination are as follows:

(1) Each Generator Company and Transmission Licensee shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, protection relay settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of their Protection System, new Protection System or changes in it.
(2) Each Transmission Licensee, Generator Company and Distributor shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the System Protection Schemes in its area confirm and that it informed to concerned RLDC about changes in status of one of its System Protection Schemes.

2. Disturbance Monitoring and Reporting

The Purpose is to ensure that adequate disturbance data is available to facilitate Grid event analysis. The analysis of power system disturbances is an important function that monitors the performance of protection system, which can provide information related to correct behavior of the system, adoption of safe operating limits, isolation of incipient faults, The Disturbance Monitoring Requirements Shall include the following:

(1) Each Transmission Licensee and Generator Company shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control and Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plants Digital (or Distributed) Control System (DCS) or part of Fault recording equipment.

This capability shall be provided at all substations and at locations to record all the events in accordance with CEA Grid Standard Regulation, 2010. The following shall also be monitored at each location:

1.1.1 Transmission and Generator circuit breaker positions

1.1.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.1.1.

1.1.3 Tele protection keying and receive

(2) In either case, a separate work station PC shall be identified to function as the event logger front end. The event logger work-station PC should be connected to UPS (Uninterrupted Power Supply).

The event logger signals shall include but not limited to

- All Circuit Breaker and isolator switching Operations
- Auxiliary supply (AC, DC and DG) supervision alarms
- Auxiliary supply switching signals
- Fire-fighting system operation alarms
- Operation signals (Alarm/Trip from all the protection relays.)
- Communication Channel Supervision Signals.
- Intertrip signals receipt and send.
- Global Positioning System (GPS) Clock healthiness.
- Control Switching Device healthiness (if applicable).
- RTU/Gateway PC healthiness
- All Circuit Breaker Supervision Signals.
- Trip Circuit Supervision Signals.

(3) Each Transmission Licensee shall provide Disturbance recording capability for the following Elements at facilities:

3.1 All transmission lines.

3.2 Autotransformers or phase-shifters connected to busses.

3.3 Shunt capacitors, shunt reactors.

3.4 Individual generator line interconnections.

3.5 Dynamic VAR Devices.

3.6 HVDC terminals.

3.7 Bus Bars

(4) The Disturbance recording feature shall be enabled and configured in all the numerical relays installed.

(5) Each Generator Company shall provide Disturbance recording capability for Generating Plants in accordance with the CEA Technical Standards for Connectivity and CEA Technical Standards for Construction of Plants.

(6) Each Transmission Licensee and Generator Company shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following:

6.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

6.2 Three phase currents and neutral currents.

6.3 Polarizing currents and voltages, if used.

6.4 Frequency.

6.5 Real and reactive power.

The Minimum parameters to be monitored in the Fault record shall be specified by the respective RPC.

(7) Each Transmission Licensee and Generator Company shall provide Disturbance recording with the following capabilities:

7.1 The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.

7.2 Each Fault record duration and the trigger timing shall be settable and set for a minimum 2 second duration including 300ms pre-fault time.

7.3 Each Fault recorder shall have a minimum recording rate of 64 samples per cycle.

7.4 Each Fault recorder shall be set to trigger for at least the following:

Internal protection trip signals, external trigger input, analog triggering (any phase current exceeding 1.5 pu of CT secondary current or any phase voltage below 0.8pu, neutral/residual overcurrent greater than 0.25pu of CT secondary current). Additional triggers may be assigned as necessary.

(8) Each Transmission Licensee and Generator Company shall establish a maintenance and testing program for Disturbance Recorder (DR) that includes

8.1 Maintenance and testing intervals and their basis.

8.2 Summary of maintenance and testing procedures.

8.3 Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control center staffed around the clock, 24 hours a day, 7 days a week (24/7)).

8.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).

8.5 Monthly verification of active analog quantities.

8.6 A requirement to return failed units to service within 90 days. If a Disturbance Recorder (DR) will be out of service for greater than 90 days, the Transmission Licensee and Generator Company shall keep a record of efforts aimed at restoring the DR to service.

(9) Each LDC, Transmission Licensee and Generator Company shall share requisite data within 15 days upon request. Each LDC, Transmission Licensee and Generator Company shall provide appropriate recorded disturbance data from DRs within 15 days of receipt of the request in each of the following cases:

9.1 CEA, RPCs/State, other LDC.

9.2 Request from other Transmission Licensee and Generator Company connected with Inter State Transmission System (ISTS).

(10) Each Transmission Licensee and Generator Company shall submit the data files to the appropriate RLDC conforming to the following format requirements:

10.1 The data files shall be submitted in COMTRADE and PDF format.

10.2 File shall have contained the name of the Relay, name of the Bay, station name, date, time resolved to milliseconds, event point name, status.

The DR archives shall be retained for a period of three years.

(11) A separate work-station PC, powered through UPS (Uninterrupted Power Supply) shall be identified with access to all the relays for extraction of DR. Auto-Download facility shall be established for automatic extraction of the DR files to a location on the work- station PC.

(12) Time Sync Equipment

12.1 Each substation shall have time synch equipment to synchronize all the numerical relays installed. Before any extension work, the capability of the existing Time-sync equipment shall be reviewed to ensure the synchronization of upcoming numerical relays.

12.2 The status of healthiness of the time-sync device shall be wired as “Alarm” to SCADA and as an “Event” to Event Logger.

12.3 The time synch status of all the installed numerical relays and event logger shall be monitored monthly and recorded. The Monthly records for relays not in time-sync shall be reported to appropriate RLDC and RPC. This record shall be archived for a period of three years by each concerned agency.

(13) Disturbance Analysis and Reporting

13.1 Subsequent to every tripping event, the concerned utility shall submit all the relevant DR files in COMTRADE and PDF format along with SOE, to the appropriate Load Dispatch Centre, regional power committee, Remote End Entity and the entity connected to the downstream of transformers (in case of transformer tripping).

13.2 Each utility shall develop internal procedure of disturbance analysis. Necessary software shall be available with the entities to view and analyse the fault record files in COMTRADE and PDF format. The detailed analysis report shall identify the reason of fault, detailed sequence of events, mis-operations identified (if any), reason of protection mis- operation and corrective actions taken. Every entity shall submit the detailed analysis report within one week of the date of event occurrence, to the appropriate load dispatch center.

13.3 A monthly report shall be prepared by each utility, mentioning the events of protection misoperations whose reasons could not be identified and require further follow-up. This report for each month shall be submitted to RPC and RLDC within the first week of the subsequent month.

13.4 The detailed analysis reports shall be archived periodically. The archive shall be retained for a period of three years by each concerned agency.

13.5 The analysis reports shall be discussed in the Appropriate Sub-Committee meetings of the RPC to be held periodically. The Appropriate Sub-Committee shall identify the lessons learnt during the events being discussed.

The Appropriate Sub-Committee shall scrutinize the correctness of operation of subject protection systems put in place by the concerned Constituents. It shall also recommend the appropriate remedial measures for system improvement.

13.6 Each RPC/RLDC shall develop and maintain a web based portal to act as a data repository with the facility for utilities to upload the fault records, analysis reports and protection relay settings.

3. Protection System Misoperation Reporting and Monitoring of Corrective Action:

(1) Definition of Misoperation:

1. Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
2. Any operation of a Protection System for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
3. Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

(2) Objectives:

1. Review all Protection System operations to identify the misoperations of Protection Systems.
2. Analyze misoperations of Protection Systems to identify the cause(s).
3. Develop and implement Corrective Action Plans to address the cause(s) of misoperations of Protection Systems.
4. Monitoring of implementation of corrective action plans.

(3) Requirements

1. Each Transmission Licensee, Generator Company, and Distribution Licensee that owns interrupting device that operated under the circumstances in Parts 1.1 through 1.3 shall, within 24 hours of the interrupting device operation, identify and report to respective SLDC/RLDC or NLDC whether its Protection System component(s) caused a Misoperation.
   1.1 The interrupting device operation was caused by a Protection System or by manual intervention in response to a Protection System failure to operate; and
   1.2 The interrupting device owner owns all or part of the Protection System; and
   1.3 The interrupting device owner identified that its Protection System component(s) caused the interrupting device(s) operation or was caused by manual intervention in response to its Protection System failure to operate.
2. When Protection System is shared among two or more utilities, each Transmission Licensee, Generator Company, and Distribution Licensee that owns an interrupting device that operated by protection system or by manual intervention in response to a protection system failure to operate, shall, within 24 hours of the interrupting device operation, provide information to the other utilities as well as respective SLDC/RLDC

or NLDC that share Misoperation identification responsibility for the Protection System under the following circumstances:

2.1 The interrupting device owner has determined that a Misoperation occurred or cannot rule out a Misoperation; and

2.2 The interrupting device owner has determined that its Protection System component(s) did not cause the interrupting device(s) operation or cannot determine whether its Protection System components caused the interrupting device(s) operation.

For an interrupting device operation by a Protection System component intended to operate as backup protection for a condition on another entity's Power System Element, information of the operation shall be provided to the other Protection System utilities for which that backup protection was provided.

3. Each Transmission Licensee, Generator Company, and Distribution Licensee that receives information, pursuant to Requirement 2 shall, within 48 hours of the interrupting device(s) operation, identify whether its Protection System component(s) caused a Misoperation.
4. Each Transmission Licensee, Generator Company, and Distribution Licensee that has not determined the cause(s) of a Misoperation, for a Misoperation identified in accordance with Requirement 1 or 3, shall perform investigative action(s) to determine the cause(s) of the Misoperation at least once in a month after the Misoperation was first identified, until one of the following completes the investigation. The duration of investigation shall not be more than 3 months from the date of misoperation.
    - The identification of the cause(s) of the Misoperation; or
    - A declaration that the operation is not misoperation.
5. Each Transmission Licensee, Generator Company, and Distribution Licensee that owns the Protection System component(s) that caused the Misoperation shall, within one month of first identifying a cause of the Misoperation:
    - Develop a Corrective Action Plan (CAP) along with the root cause analysis/ investigation report for the identified Protection System component(s), and an evaluation of the CAP's applicability to the entity's other Protection Systems including other locations and submit the same to RPCs; or
    - Explain in a declaration why corrective actions are beyond the entity's control or would not improve Grid reliability, and that no further corrective actions will be taken.
6. Each Transmission Licensee, Generator Company, and Distribution Licensee shall implement each CAP developed in Requirement 5, and update each CAP if actions or timetables change, until completed.
7. RPCs shall deliberate the reported misoperation in Appropriate Sub- Committee meetings and monitor the implementation of CAP.

(4) Measures of Compliance:

Each Transmission Licensee, Generator Company, and Distribution Licensee shall have dated evidence that demonstrates the followings:

1. It identified and reported the Misoperation of its Protection System component(s), if any, that meet the circumstances in Requirement 1 within the allotted time period.
2. It informed to the other owner(s), within the allotted time period for Requirement 2.

3. It identified whether its Protection System component(s) caused a Misoperation within the allotted time period for Requirement 3.
4. It performed at least one investigative action according to Requirement 4 at least once in a month until a cause is identified or a declaration is made.
   Acceptable evidence for Requirement 1,2,3 & 4 may include, but is not limited to the following dated documentation (electronic or hardcopy format): reports, databases, spreadsheets, emails, facsimiles, lists, logs, records, declarations, analyses of sequence of events, relay targets, Disturbance Recorder (DR) and Event Logger (EL) records, test results, or transmittals.
5. It developed a CAP and an evaluation of the CAP's applicability to other Protection Systems and locations, or a declaration in accordance with Requirement 5. Acceptable evidence may include, but is not limited to the following dated documentation (electronic or hardcopy format): CAP and evaluation, or declaration.
6. It implemented each CAP, including updating actions or timetables. Acceptable evidence may include, but is not limited to the following dated documentation (electronic or hardcopy format): records that document the implementation of each CAP and the completion of actions for each CAP including revision history of each CAP. Evidence may also include work management program records, work orders, and maintenance records.
7. RPCs shall maintain the updates of implementation of CAP.

4. Monitoring of System Protection Scheme (SPS) Misoperation:

(1) Definition of SPS Misoperation:

SPS misoperations are defined as follows:

1. Failure to Operate – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occurs;
2. Failure to Arm – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;
3. Unnecessary Operation – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s);
4. Unnecessary Arming – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
5. Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the system design intent.

(2) Objectives:

1. Reporting of all System Protection Scheme (SPS) Misoperations
2. Analysis of all System Protection Scheme (SPS) Misoperations and/or
3. Mitigation of all System Protection Scheme (SPS) Misoperations.

(3) Requirements:

1. System Operational Personnel and System Protection personnel of the Transmission Licensee and Generator Company shall analyze all SPS operations.

1.1. System Operational Personnel and System Protection Personnel shall report and review all SPS operations to RPCs/RLDCs/NLDC to identify apparent Misoperations within 24 hours.

1.2. System Protection Personnel shall analyze all operations of SPS within seven working days for correctness to characterize whether a Misoperation has occurred that may not have been identified by them.

2. Transmission Licensee and Generator Company shall perform the following actions for each Misoperation of the SPS. If SPS actions that appear to be entirely reasonable and correct at the time of occurrence and associated system performance is fully compliant with IEGC/ CEA Standards the following requirements shall not be applicable. If the Transmission Licensee or Generator Company later finds the SPS operation to be incorrect through their analysis, the following requirements become applicable at the time the Transmission Licensee or Generator Company identifies the Misoperation:

2.1. If there is an SPS Misoperation Transmission Licensee and Generator Company shall repair and place back in service within 24 hours the SPS that misoperated. If this cannot be done, then

2.1.1 Transmission Licensee and Generator Company shall report to respective SLDC/RLDC or NLDC for necessary action to adjust generation and line flows to a reliable operating level.

2.1.2 SLDC/RLDC/NLDC shall give instructions to concerned utilities to operate the facilities within permissible limits.

2.1.3 Transmission Licensee and Generator Company shall perform the instructions of SLDC/RLDC/NLDC as soon as they received and report back to respective SLDC/RLDC or NLDC for the implementation of the same.

3. Transmission Licensee and Generator Company shall submit Misoperation incident reports to NLDC/RLDCs/RPCs within seven working days for the following.

3.1. Identification of a Misoperation of a SPS,

3.2. Completion of repairs or the replacement of SPS that misoperated.

4. SPS shall be reviewed at least once in a year or whenever any change in network/ modification.

(4) Measures of Compliance:

1. System Operational Personnel and System Protection personnel of the Transmission Licensee and Generator Company shall have evidence that they reported and analyzed all SPS operations.

1.1 Transmission Licensee and Generator Company shall have evidence that they reviewed all operations of SPS within 24 hours.

1.2 Transmission Licensee and Generator Company shall have evidence that they analyzed all operations of SPS for correctness within seven working days.

2. Transmission Licensee and Generator Company shall have evidence that they have repaired and replaced the SPS that misoperated from service within 24 hours following identification of the SPS Misoperation.

2.1 The Generator Company and Transmission Licensee shall have documentation describing all actions in accordance with Requirements 2.1.1 and 2.1.3.SLDC/RLDC/NLDC shall have the evidence in accordance with the Requirements 2.1.2.

3. Transmission Licensee and Generator Company shall have evidence that they reported to NLDC/RLDCs/RPCs about the following within seven working days.
   3.1 Identification of all SPS Misoperations and corrective actions taken or planned.
   3.2 Completion of repair, replacement of, or SPS that misoperated.
4. Transmission Licensee and Generator Company shall have evidence that they reviewed SPS at least once in a year or whenever any change in network/ modification.

5. Transmission and Generation Protection System Maintenance and Testing

(1) Definitions:

1. **Protection System:** The Protection System includes Protection relays, associated communication system, System Protection Schemes, voltage and current sensing devices, DC control circuit, battery, circuit breakers & associated Trip Circuits etc. Protection relays shall also include Under Frequency Relays and Under Voltage Relays.
2. **Maintenance**: An ongoing program by which Protection System function is proved, and restored if needed. A maintenance program comprises verification of individual protection systems, which in turn is achieved by of a combination of monitoring, testing, and calibration.
3. **Testing:** Application of signals to a Protection System or component removed from service, to observe functional performance or output behavior.

(2) Objective:

To ensure all transmission and generation Protection Systems affecting the Grid reliability are maintained and tested.

(3) Requirements:

1. Each Transmission Licensee and each Generator Company that owns a generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that connected to Grid. The program shall include:
   1.1. Preventive maintenance and testing intervals and their basis.
   1.2. Summary of maintenance and testing procedures.
   1.3. Responsibilities of concerned wings of Licensee
2. Each Transmission Licensee and each Generator Company that owns a generator interconnection Facility Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to the concerned RPCs as per the Table A. The documentation of the program implementation shall include:
   2.1. Evidence of Protection System devices were maintained and tested within the defined intervals.
   2.2. Date of each Protection System device was last tested/maintained.

(4) Measures of Compliance:

1. Each Transmission Licensee and each Generator Company that owns a generator interconnection Facility Protection System that affects the Grid reliability, shall have an associated Protection System maintenance and testing program as defined in Requirement 1.
2. Each Transmission Licensee and each Generator Company that owns a generator interconnection Facility Protection System that affects the Grid reliability, shall have evidence it provided documentation of its associated Protection System maintenance and testing program and the implementation of its program as defined in Requirement 2.
3. Retention of Records: The verification records for a particular protection system or component should be retained at least until successful completion should be retained for at least three years.

TABLE A- Maximum Allowable Testing Intervals by Equipment Category				
Category	**Component**	**Maximum verification interval**		**Verification Activities**
		Unmonitored	**Monitored**	
1.	Testing and calibration of protective relays.	3 years	Continuous monitoring and verification	Test the functioning of relays with simulated inputs, including calibration. Verify that settings are as specified.
2.	Verification of Instrument transformer outputs and correctness of connections to protection system.	3 years	Continuous monitoring and verification	Verify the current and voltage signals to the protection system, and instrument transformer circuit grounding
3.	Verification of protection system tripping including circuit breaker tripping, auxiliary tripping relays and devices, lockout relays, telecommunications assisted tripping schemes, and circuit breaker status indication required for correct operation of protection system.	3 years	Continuous monitoring and verification	Perform trip tests for the whole system at once, and/or component operating tests with overlapping of component verifications. Every operating circuit path must be fully verified, although one check of any path is sufficient. A breaker only need be tripped once per trip coil within the specified time interval. Telecommunications-assisted line protection systems may be verified either by end-to-end tests, or by simulating internal or external faults with forced channel signals.

4.	Station battery supply	1 month	Continuous monitoring and verification	Verify voltage of the station battery once a month if not monitored.
5.	Protection system telecommunications equipment and channels required for correct operation of protection systems.	3 months	Continuous monitoring and verification	Check signal level, signal to noise ratio, or data error rate within the specified interval. This includes testing of any function that inhibits undesired tripping in the event of communications failure detected by partial or thorough monitoring. For partially or thoroughly monitored communications, verify channel adjustments and monitors not verified by telecommunications self-monitoring facilities (such as performance and adjustment of line tuners and traps in power line carrier systems). For thoroughly monitored systems, check for proper functioning of alarm notification.
6.	Testing and calibration of (Under Voltage Load Shedding) UVLS and (Under Frequency Load Shedding) UFLS relays that comprise a protection scheme distributed over the power system.	3 years	Continuous monitoring and verification	Test the functioning of relays with simulated inputs, including calibration. Verify that settings are as specified. Verification does not require actual tripping of loads.
7.	SPS, including verification of end-to-end performance, or relay sensing for centralized UFLS or UVLS systems.	1 year	Continuous monitoring and verification	Perform all of the verification actions for Categories 1 through 5 above as relevant for components of the SPS, UFLS or UVLS systems. The output action may be breaker tripping, or other control action that must be verified. A grouped output control action need be verified only once within the specified time interval, but all of the SPS, UFLS, or UVLS components whose operation leads to that control action must each be verified.

Unmonitored – Applies to electromechanical and analog solid-state protection systems.

Monitored – Applies to microprocessor relays and associated protection system components in which every element or function required for correct operation of the protection system is monitored continuously or verified, including verification of the means by which failure alarms or indicators are transmitted to a central location for immediate action. For monitored systems or segments, documentation is required that shows how every possible failure, including a failure in the verification or monitoring system or alarming channel, is detected.

6. System Protection Scheme Review Procedure

(1). Definition:

A documented SPS review procedure to ensure that SPSs comply with Regional criteria and various Standards and Regulations.

(2). Objective:

1. To ensure that all System Protection Schemes (SPS) are properly designed, meet performance requirements, and are coordinated with other protection systems.
2. To ensure that maintenance and testing programs are developed and misoperations are analysed and corrected.

(3). Requirements:

1. Each RPC that uses or is planning to use an SPS shall have a documented SPS review procedure to ensure that SPSs comply with Regional criteria and various Standards and Regulations. The Regional SPS review procedure shall include:
   - 1.1. Description of the process for submitting a proposed SPS for RPC review.
   - 1.2. Requirements to provide data that describes design, operation, and modeling of an SPS.
   - 1.3. Requirements to demonstrate that the SPS are designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the power system elements from meeting the requirements Central Electricity Authority (Grid Standards) Regulations.
   - 1.4. Requirements to demonstrate that the inadvertent operation of an SPS shall meet the requirement of CEA's Transmission Planning Criterion as that required of the contingency for which it was designed.
   - 1.5. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable emergency procedures.
   - 1.6. Definition of mis-operation (in consistent with the definition mentioned in the item of these standards" Monitoring of System Protection Scheme (SPS) Mis-operation").
   - 1.7. Requirements for analysis and documentation of corrective action plans for all SPS mis-operations.
   - 1.8. Identification of the Subgroup at the regional level responsible for the SPS review procedure and the process for approval of the procedure.
   - 1.9. Determination, as appropriate, of maintenance and testing requirements.

2. The RPC shall provide other RPCs and CEA/NLDC with documentation of its SPS review procedure on request (within 30 calendar days).

(4). Measures of Compliance:

1. The RPC using or planning to use an SPS shall have a documented review procedure as defined in Requirement 1.
2. The RPC shall have evidence it provided other RPCs and CEA/NLDC with documentation of its SPS review procedure on request (within 30 calendar days).

7. Transmission Relay Loadability

(1). Definition:

Transmission Relay Loadability means the loading permitted in the transmission line by the relay including a security margin. The relay loadability is to be arrived in such a way as far as possible not to interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. Transmission relay do not prematurely trip the transmission elements out-of-service and allow the system operators from taking controlled actions consciously to alleviate the overload.

(2). Objective:

Protective relay settings shall

1. Not limit transmission loadability;
2. Not interfere with system operators' ability to take remedial action to protect system reliability and;
3. Be set to reliably detect all fault conditions and protect the electrical network from these faults.
4. This standard includes any protective functions which could trip with or without time delay, on load current i.e. load responsive phase protection systems including but not limited to:
    - i. Phase distance.
    - ii. Out-of-step tripping.
    - iii. Switch-on-to-fault.
    - iv. Overcurrent relays.
    - v. Communications aided protection schemes including but not limited to:
        - Permissive overreach transfer trip (POTT).
        - Permissive under-reach transfer trip (PUTT).
        - Directional comparison blocking (DCB).
        - Directional comparison unblocking (DCUB).
    - vi. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

5. The following protection systems are excluded from requirements of this standard:
    - i. Relay elements that are only enabled when other relays or associated systems fail. For example:
        - Overcurrent elements that are only enabled during loss of potential conditions.
        - Elements that are only enabled during a loss of communications except as noted in section 4 (vi)
    - ii. Protection systems intended for the detection of ground fault conditions.
    - iii. Protection systems intended for protection during stable power swings.
    - iv. Relay elements used only for System Protection Schemes.
    - v. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

vi. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
vii. Relay elements associated with dc lines.
viii. Relay elements associated with dc converter transformers.

(3). Requirements:

1. Each Transmission Licensee, Generator Company, or Distribution Licensee shall use any one of the following criteria for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Grid for all fault conditions. Each Transmission Licensee, Generator Company, or Distribution Licensee shall evaluate relay loadability at 0.90 per unit voltage and a power factor angle of 30 degrees.
   Criteria:
   i. For Distance protection relays of transmission lines, the Zone-3 shall prevent load encroachment, considering the following criteria
      a. Maximum load current (I_{max}) may be considered as 1.2 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.
         (The rating considered is approximately 15 minutes rating of the Transmission facility).
      b. For setting angle for load blinder, a value of 30 degree may be adequate in most cases.
      c. The Distance protection relays shall have provision for load blinder characteristic or load encroachment detection.
   ii. For Directional Overcurrent relays, wherever used in a transmission line (132kV level), the following shall be adopted.
      a. An overload alarm shall be set at 110% of the thermal rating of the line with sufficient delay. This alarm shall allow the operator to take corrective action.
      b. The Directional Overcurrent relay shall allow the line to carry 1.5 times of the associated line or bay equipment current rating (whichever is lower) till 10 minutes.
   iii. For transformer protection relays the following shall be adopted
      - Set the definite time transformer overload relay at 105% of the transformer ratings with sufficient delay. It shall be wired for alarm purpose only to allow the operator to take corrective action. No tripping shall be issued from this relay.
      - Set the transformer overload tripping at 110% of the transformer nameplate rating.
      - The back-up overcurrent relays shall use IDMT characteristics and be suitably coordinated with the upstream transmission network.
      - Install supervision for the transformer using either a top oil or simulated winding hot spot temperature element. The alarm and trip settings for these relays shall be set by individual entities based on the manufacturer’s recommendation.
2. Each Transmission Licensee, Generator Company, or Distribution Licensee that uses thermal rating of circuit as described in above requirement may use the thermal ratings as specified in CEA’s Manual on Planning Criterion.
3. Each Transmission Licensee, Generator Company, or Distribution Licensee which experience the load encroachment (despite setting the relay in accordance with this standard) or overloading of transmission line/ transformers, shall submit a report in this

regard to respective RPC within a month to allow the RPC to compile a list of all elements that have persistent overloading or load encroachment condition.

(4). Measures of Compliance:

1. Each Transmission Licensee, Generator Company, or Distribution Licensee shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to the standard and do not expose the transformer to fault levels and durations beyond those indicated in the standard.
2. Each Transmission Licensee, Generator Company, or Distribution Licensee shall have evidence such as rating spreadsheets or rating database to show that it used the thermal rating as per Requirement 2.
3. Each Transmission Licensee, Generator Company, or Distribution Licensee shall have evidence such as dated correspondence that it provided an updated list of the elements in accordance with the Requirement 3 of this standard. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list.

8. Relay Performance During Stable Power Swings

(1). Definition:

1. **Power Swing**: A variation in three phase power flow which occurs when the generator rotor angles are advancing or retarding relative to each other in response to changes in load magnitude and direction, line switching, loss of generation, faults, and other system disturbances.
2. **Stable Power Swing**: A power swing is considered stable if the generators do not slip poles and the system reaches a new state of equilibrium, i.e. an acceptable operating condition.
3. **Unstable Power Swing:** A power swing that will result in a generator or group of generators experiencing pole slipping for which some corrective action must be taken.

(2). Objective:

1. To ensure that load-responsive protective relays are expected to not trip in response to stable power swings during non-Fault conditions.
2. This standard applies to the following protective functions including, but not limited to:
   - Phase distance
   - Phase overcurrent
   - Out-of-step tripping
   - Loss-of-field

   The following protection functions are excluded from Requirements of this standard:
   - Relay elements supervised by power swing blocking
   - Relay elements that are only enabled when other relays or associated systems fail. For example:
     - Overcurrent elements that are only enabled during loss of potential conditions.
     - Relay elements that are only enabled during a loss of communications
   - Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
   - Relay elements associated with direct current (dc) lines
   - Relay elements associated with dc converter transformers

- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (i.e., in order to prevent false operation in the event of a loss of potential)
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays

(3). Requirements:

1. Each RPC shall, at least once each calendar year, provide information of generator, transformer, transmission line or other Grid element in its area that meets one or more of the following criteria, if any, to the respective Generator Company and Transmission Licensee:

   Criteria:

   i. Generator(s) having an angular stability constraint that is addressed by a SPS and Elements of Associated Transmission System.
   ii. Transmission elements having limitation due to angular stability limit and elements of Inter-regional and Inter-area importance.
   iii. Elements that form the boundary of an island that are formed by tripping the Elements based on angular instability.
   iv. Elements identified in the most recent Grid Disturbance/Grid Incidence where relay tripping occurred due to a stable or unstable power swing or the Elements identified in the most recent Planning system studies where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.
2. Each Generator Company and Transmission Licensee in consultation with CTU/STU and respective RLDC/RPC shall:

   2.1 Within 3 calendar months of notification of a Grid Element pursuant to Requirement 1, determine whether its load-responsive protective relay(s) applied to that Grid Element meets the following criteria.

   Criterion A:

   An impedance-based relay used for tripping is expected to not trip for a stable power swing, when the relay characteristic is completely contained within the unstable power swing region. The unstable power swing region is formed by the union of three shapes in the impedance (RX) plane; (1) a lower loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 0.7; (2) an upper loss-of-synchronism circle based on a ratio of the sending-end to receiving-end voltages of 1.43; (3) a lens that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending-end and receiving-end voltages from 0.0 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

   i. The system separation angle is:
      - At least 120 degrees, or

- An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.

ii. All generation is in service and all transmission Grid Elements are in their normal operating state when calculating the system impedance.

iii. Saturated (transient or sub-transient) reactance is used for all machines.

Criterion B:

The pickup of an overcurrent relay element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

i. The system separation angle is:
   - At least 120 degrees, or
   - An angle less than 120 degrees where a documented transient stability analysis demonstrates that the expected maximum stable separation angle is less than 120 degrees.

ii. All generation is in service and all transmission Grid Elements are in their normal operating state when calculating the system impedance.

iii. Saturated (transient or sub-transient) reactance is used for all machines.

iv. Both the sending-end and receiving-end voltages at 1.05 per unit.

2.2 Within 3 calendar months of becoming aware of a generator, transformer, or transmission line Grid Element that tripped in response to a stable or unstable power swing due to the operation of its protective relay(s), determine whether its load-responsive protective relay(s) applied to that Grid Element meets the criteria A & B.

3. Each Generator Company and Transmission Licensee shall, within 3 calendar months of determining a load-responsive protective relay does not meet the criteria A & B pursuant to Requirement 2, develop a Corrective Action Plan (CAP) to meet one of the following:
   - The Protection System meets the criteria A & B, while maintaining dependable fault detection and dependable out-of-step tripping (if out-of- step tripping is applied at the terminal of the Grid Element); or
   - The Protection System is excluded as mentioned in objective of this standard (e.g., modifying the Protection System so that relay functions are supervised by power swing blocking or using relay systems that are immune to power swings), while maintaining dependable fault detection and dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Grid Element).
4. Each Generator Company and Transmission Licensee shall implement each CAP developed pursuant to Requirement 3 and update each CAP if actions or timetables change until all actions are complete.

(4). Measures of Compliance:

1. Each RPC shall have dated evidence that demonstrates it provides the information of the generator, transformer, and transmission line/Grid Element(s) that meet one or more of the criteria in Requirement 1, if any, to the respective Generator Company and Transmission Licensee. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.
2. Each Generator Company and Transmission Licensee shall have dated evidence that demonstrates the evaluation was performed according to Requirement 2. Evidence may include, but is not limited to, the following documentation: apparent impedance

characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

3. The Generator Company and Transmission Licensee shall have dated evidence that demonstrates the development of a CAP in accordance with Requirement 3.
4. The Generator Company and Transmission Licensee shall have dated evidence that demonstrates implementation of each CAP according to Requirement 4, including updates to the CAP when actions or timetables change.

   Evidence in Measures 3 & 4 may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

9. Time Synchronization:

(1) Definition:

Time/clock synchronization in Power system means to coordinate independent clocks with the reference to an accurate external time source, such as a GPS time signal.

[Intelligent electrical devices (IEDs) have their own clocks, but electronic clocks are subject to drift. Even when updated frequently over a network by application software, their clocks may vary from each other by as much as a second. Because several events can occur during this time frame, modern power systems require more precise coordination to ensure high reliability]

(2) Objective:

1. To have precise time synchronization for a variety of Intelligent Electronic Devices (IEDs).
2. To have accurate time synchronization to ensure high reliability of power system
3. To have accurate time synchronization for proper fault analysis.
4. Time synchronization for substations with integrated protection and system control functions, as well as data collection require a target architecture that distributes synchronized time in several ways.

(3) Requirements:

1. Each substation shall have time synchronization equipment including external time source to synchronize all the numerical relays installed. Before any extension work, the capability of the existing time synchronization equipment shall be reviewed to ensure the synchronization of upcoming numerical relays.
2. The status of healthiness of the time synchronization equipment shall be wired as “Alarm” to SCADA and as an “Event” to Event Logger.
3. The time synchronization status of all the installed numerical relays and event logger shall be monitored monthly and recorded.
4. The Monthly records for relays not in time synchronization shall be reported to concerned SLDC/RLDC and RPC. This record shall be archived for a period of three years by each concerned agency.
5. Remedial action shall be taken by the concerned substation/ Protection department immediately to make the relays in time synchronization with reference to external time source.
6. All the new Grid elements/Bay extension shall have accurate and precise Time synchronization equipment.

(4) Measures of Compliance:

1. Each substation shall have evidence that it reviewed the capability of the existing time synchronization equipment before any extension work for synchronization upcoming numerical relays.
2. Each substation shall review the status of healthiness of the time synchronization equipment being recorded.
3. Each substation shall have evidence that the time synchronization status of all the installed numerical relays and event logger are monitored monthly and recorded.
4. Each substation shall have evidence that the monthly records for relays not in time synchronization are reported to concerned SLDC/RLDC and RPC.
5. Each substation or concerned protection department shall have evidence that remedial action was taken to make the relays in time synchronization with reference to external time source.
6. Each entity, which has commissioned new Grid elements/Bay extension, shall have evidences that it has provided precise and accurate time synchronization equipment.

10. DC system

(1) Definition:

DC system consists of battery charger and battery sets**.** DC batteries are used to provide back up to control power supply to all the protection, control, communication and automation equipment for fail safe operation of the substation.

(2) Objective:

To have the required capacity and to test the condition of DC system for a reliable, dependable and secured DC Power Supply Block and form essential part of the protection control, communication and automation equipment in the substation.

(3) Requirements:

1. DC system shall comprise of Battery and a Battery Charger in parallel operation. In this mode, the charger shall be required to not only continuously feed a variable load but also deliver trickle/boost charging current for the battery at desired rate. Battery will be capable of feeding the DC load requirement of the Sub-station in case of failure of the charger. DC system at each voltage level shall have minimum of two sets of batteries. Each battery set shall cater 100% of its DC system load. One float-cum-boost charger shall be provided for each battery. Battery shall conform to relevant IS.

2. Each battery shall have sufficient capacity considering continuous and intermittent loads for the periods specified below and for all bays (i.e. present and future bays) with the charger out of service:
   a) Continuous DC load for protection, control, indications, alarms and interlock for 10 hours.
   b) Intermittent DC load for closing and tripping operation of Circuit Breakers, Isolators and Earth Switches. This load shall be determined considering simultaneous tripping of breakers on bus-bar protection for 220kV and above substations. Duration of intermittent load shall be considered as one minute.

3. Each utility shall carry out testing activities of Battery sets and Battery chargers as per procedures and periodicity as mentioned in the manufacturer's manual.

4. Each utility shall follow the maintenance schedules of DC system as given in Table.

Table

Daily	• Checking of DCDB: P-E, N-E & P-N voltage for earth fault in Main DCDBs. • Charger: Trickle/ Float charging Current(1.4mA/Ah for Lead Acid, & 2.0mA/Ah for Ni-Cd): Adjustment if required to be done in Float voltage of the charger. • Checking of pilot cell* voltage (2.25 ± 0.02V at 20-35degC for Lead Acid & 1.4-1.42V for Ni-Cd). • Checking of pilot cell*specific gravity (not applicable for Ni-Cd& VRLA) (Specific Gravity 1.200 ± 0.005 at 27 degC)
Weekly	• Checking of Electrolyte level and any spillage / crack cells. • General appearance, cleanliness of the battery and battery area. • Any evidence of sulphation / corrosion at either terminals or connectors. • Battery Room: Condition of ventilation equipment. • Availability of tap water/safety shower in Battery room. • Ambient temperature to be recorded and maintained.
Monthly	• Charger output current and voltage recording and adjustment if required, • Voltage of each cell and total battery terminal voltage. • Checking for AC/DC mixing in DCDBs.
Quarterly	• Specific gravity of each cell (not applicable for Ni-Cd& VRLA) • Temperature of electrolyte of representative cells.
Half yearly	• Boost Charging of battery sets for Ni-Cd battery only.
Yearly	• Batteries of all types: Capacity Test as per procedure of OEM for the installed battery type or IS14782 / IEEE 450 to be followed for lead acid and IEEE-1106 for Ni-Cd battery banks. The tightness of cell connections on individual terminals should be ensured. • Chargers: Load Test of chargers & overhauling. Ripple Content measurement of chargers (3-4%). Record and compare with charger spec. If ripple is high, check & rectify filters. • Overhauling of DCDB

Abbreviations:-

- DCDB: DC Distribution Board
- P-E :Positive to Earth
- N-E :Negative to Earth
- P-N :Positive to Negative
- VRLA: Valve Regulated Lead Acid
- Ni-Cd :Nickel Cadmium
- Ah : Ampere hour

(4). Measures of Compliance:

1. Each utility shall have evidence as per Requirement 1.

2. Each utility shall have evidence that substation battery sets have sufficient capacity considering continuous, emergency and intermittent loads for the periods specified under Requirement 2.
3. Each utility shall keep the testing reports of charger and battery sets in substation at least for the duration of 3 years.
4. Each utility shall keep the evidence of maintenance schedules of DC system carried out according to the Requirement 4 at least for the duration of 3 years.

11. Compliance Monitoring of Reliability Standard for Protection system

1. RPC shall be responsible for the compliance monitoring for Reliability Standard for Protection system.
2. The following methods shall be used to assess compliance:
   (i) Self-certification (annually and submit to RPC)
   (ii) Periodic Protection Audit (Conduct once in a year for critical substations as listed by RPC and once in four years for other substations according to schedule prepared by RPC)
   (iii) Triggered Protection Audit (Conduct within 30 days for the substation where Grid Incident/ Disturbance occurred or complaint of noncompliance.)
3. The RPC shall constitute a Protection Audit team with representative of RPC / NPC Secretariat, CTU or POSOCO, STU/entity other than STU/entity being audited to assess compliance. The checklist for the protection audit shall be finalized in the appropriate subcommittee of RPC.
4. The review of the Protection Audit report shall be carried out in appropriate subcommittee of RPC.
5. The owner of the new transmission asset shall submit the Reliability Standard compliance certificate to respective SLDC/RLDC or NLDC for allowing the connection of the respective asset to the grid under intimation to RPC.
6. All the Transmission licensee, Generator Company and Distribution Licensee shall keep evidence to validate the compliance of the Reliability standard for Protection system and protection audit reports.
7. RPC shall keep all compliance monitoring reports/audit reports at least for five years.