CENTRAL ELECTRICITY AUTHORITY
NATIONAL POWER COMMITTEE

Summary Record of Discussions in the Third Meeting of Subgroup for Preparation of Reliability Standards for Protection System and Communication System held on 20th January 2017 at New Delhi

1. **Introduction:**

The 3rd Meeting of the Subgroup for preparation of "Reliability Standards for Protection System and Communication System" for Indian Power System was held on 20th January, 2017 in NRPC Conference Hall, Katwaria Sarai, New Delhi. The list of the participants is at **Annexure-I.**

Director, NPC & Member Convener of Subgroup welcomed the members of the subgroup and participants to the meeting. He informed that in the 7th meeting held on 7th December, 2016, NRCE has nominated Chief Engineer, NPC as Chairperson of this subgroup. He requested Shri B.C. Mallick, Chief Engineer, NPC to chair the meeting.

Chief Engineer, NPC welcomed the members and participants to the meeting. He observed that in the earlier meetings the Protection Standards for the following broad areas were finalized by the subgroup:

1. Definition of Protection System and its Philosophy & aspects related to Protection Coordination
2. Regional Disturbance Monitoring and Reporting

He stated that the subgroup has to finalize other identified broad areas at the earliest so that the preparation of Communication Standards could be taken up in order to complete the preparation of the Standards within six months (starting from 7th December, 2016) period decided by NRCE in its 7th Meeting.

2. **CONFIRMATION OF THE RECORD NOTES OF DISCUSSIONS IN THE SECOND MEETING OF SUBGROUP**

The Record Notes of the 2nd meeting held on 04th November 2016 was issued on 13th December 2016. PGCIL vide e-mail dated 17th January 2017 had furnished the comments on the material finalized so for (**Annexure-II)**.

The Subgroup confirmed the Record Notes of 2nd meeting with modifications in para 1.3.2(A), 1.3.2(i),1.3.2(ii), 1.3.2(h), 1.3.3.2(ii), 1.3.3.2(iv), 1.3.6 & 1.3.3.1(b). The revised material in respect of the broad areas 1 & 2 are at **Annexure III.**

3. **<u>Summary of Deliberations in the Meeting:</u>**

Director (NPC) and Member Secretary of the Subgroup sought the views/inputs of Members on the draft proposal on the items further to the items finalized so far, as mentioned below.

- (3) Protection Misoperation Reporting and Monitoring of Corrective Action
- (4) Reporting of Special Protection Scheme Misoperation
- (5) Need for sudden pressure released relay
- (7) Transmission and Generation Protection System Maintenance and Testing

3.1 The report finalized by the subgroup in respect of Protection Misoperation Reporting & Monitoring of Corrective Action, Reporting of Special Protection Scheme Misoperation and Transmission & Generation Protection System Maintenance & Testing is at **Annexure-IV**.

3.2 In respect of the broad area no. (5) 'Need for Sudden Pressure Released Relay', Subgroup noted that Sudden Pressure Released Relay are widely used in American and Europian power system. However, these relays are rarely used in Indian power system. Therefore, Subgroup was of the view that there is no significance of preparing standard for these relays.

3.3 Member Convener, Subgroup informed that broad area no. (6)' Need for Voltage collapse prediction System' is not being taken up in this meeting in view of non-availability of sufficient material. He requested PGCIL to provide material on voltage collapse prediction system. PGCIL agreed to provide the same.

Chairperson, Subgroup thanked all the members for their active participation and suggestion given.

The date and venue of the 4th meeting of the subgroup will be intimated in due course.

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ANNEXURE-I

List of Participants in the 3rd Meeting of Sub-Group of NRCE for Preparation of "Protection Standards and Communication Standards for Power System" held on 20th January 2017 at New Delhi.

Central Electricity Authority (CEA)

1. Shri B.C. Mallick, Chief Engineer (NPC)
2. Shri D.K. Srivastava, Director (NPC)
3. Shri Y.K. Swarnkar, Director (PSE&TD)
4. Shri Meka Ramakrishna, Deputy Director (NPC)
5. Shri K.P. Madhu, Deputy Director (NPC)
6. Shri Himanshu Lal, Assistant Director-I (NPC)
7. Shri Deepanshu Rastogi, Assistant Director-I (NPC)
8. Shri Akash Chhikara, Assistant Director-I (NPC)

Northern Regional Power Committee (NRPC)

1. Shri Naresh Kumar, Executive Engineer
2. Shri Akshay Dubey, Assistant Executive Engineer

North-Eastern Regional Power Committee (NERPC)

1. Shri Srijit Mukherjee, Assistant Executive Engineer

Power Grid Corporation of India Limited (PGCIL)

1. Shri Abhay Kumar, Deputy General Manager
2. Shri Brijendra B. Singh, Dy. Manager

National Thermal Power Corporation (NTPC)

1. A.K. Haldar, General Manager(OS)

Power System Operation Corporation (POSOCO)

1. N.L. Jain, Deputy General Manager
2. Rahul Shukla, Senior Engineer

ANNEXURE-II

Sr. No.	Item as per 2nd meeting Record Notes	Comments of PGCIL	Deliberations in the meeting
1.	**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) with two independent auxiliary direct current- supplies shall be provided for each of the relays and at least one of them being carrier aided non-switched three zone distance protection. The other protection may be a phase segregated current differential (this may require digital communication) phase comparison, directional comparison type or a carrier aided non-switched distance protection.	In case line lengths are very small say less than 10 km, use of distance relay is not adequate and we should resort to current differential relay. Thus, the minutes may be modified suitably.	Subgroup agreed the same and recommended to include the following: *For very short line (less than 30 km), line differential protection with distance protection as backup (built-in Main relay or standalone) shall be provided mandatorily as Main-I.*
2.	**1.3.2** In addition to above following shall also be provided: (i) Two stage over-voltage protection. However, in such cases where system has grown sufficiently or in case of short lines, utilities on their discretion may decide not to provide this protection.	Use of O/V protection is also not required for 220kV lines and neither it is presently provided.	The Subgroup agreed to revise the 1.3.2 (A) (i) as below: *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.*
3.	**1.3.2** (ii) Auto reclose relay suitable for 1 ph/3 ph (with deadline charging and synchro-check facility) reclosure.	3 Phase auto reclose we may dispense with as it is more complicated and presently nowhere used.	The Subgroup agreed to revise the 1.3.2 (A) (ii) as below: *Auto reclose relay suitable for 1 ph or 3 ph (with deadline charging and synchro- check facility) reclosure.*

4.	**1.3.2** Main Protection shall have following features: (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 at least 98% drop-off to pick-up ratio. The detection shall be made on phase to phase voltage.	Many vendor does not guarantee 98% pick up to drop off ratio. The safe limit is 97%. May be corrected accordingly.	The Subgroup agreed that the overvoltage relay shall have better than 97% drop-off to pick-up ratio as envisaged in Ramakrishna task force report. Accordingly 1.3.2 (h) has been modified.
5.	**1.3.3.2 Line Differential Protection** The differential protection shall have following requirements: (ii) The differential relays provided in 220kV and above system must operate in less than 20ms. (iv) For differential protection (current or others), in order to synchronize the analogue measurement, the maximum delay of the transmission system should be less than 10ms and the asymmetry in the pick-up times should be less than 1 ms.	The guaranteed time of 20msec is very difficult to achieve in all operating condition. Please revise it to 30 Msec. We should not over specify. Once we have specified maximum operating time these parameters are not required.	Subgroup agreed for differential relay operating time in less than 30 ms. It was agreed to remove the para 1.3.3.2 (iv)
6.	**1.3.4 Autoreclosing** 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	Consider deleting the complete para. We should not define the implementation issues.	Subgroup opined that the Scheme Special Requirements envisaged for autoreclosing are necessary and should be a part of Standards.

	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. 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.		
8.	**1.3.6.** VOLTAGE AND CURRENT INVERSION Voltage inversion on Series Compensated line: The phenomenon where the voltage at the relay point reverses its direction 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	Consider deleting.	It was agreed that the phenomenon of voltage and current inversion for distance relay may be placed appropriately. Accordingly Para 1.3.6 has been deleted and placed under Distance Protection Schemes in

	against this phenomenon. <u>Current inversion on Series Compensated line:</u> In certain cases, the fault current will lead source voltage by 90 degrees called as Current inversion which causes a false directional decision of distance relays		Para 1.3.3.1 as below: **b. Each Distance Relay:** 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.

ANNEXURE-III

(1) DEFINITIONS RELATED TO PROTECTION SYSTEM

1.1 DEFINITIONS:

This part of the standard will be formed after the completion of the whole document.

1.2 GENERAL PHILOSOPHY OF PROTECTION SYSTEM:

There shall be protection philosophy 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.

(iii) Protection relays must allow the maximum possible loadability of the protected equipment, while ensuring the clearing of anticipated faults according to the simulation studies.

(iv) 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.

(v) 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 three zone distance protection. The other protection may be a phase segregated current differential (this may require digital communication) phase comparison, directional comparison type or a carrier aided non-switched distance protection. Wherever 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 (built-in Main relay or standalone). For very short line (less than 30 km), line differential protection with distance protection as backup (built-in Main relay or standalone) shall be provided mandatorily as Main-I.

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 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 detection shall be made on phase to phase voltage.

B. For transmission line having voltages at 132kV: There should be at least one carrier aided non-switched three 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 phenomenons.

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), if OPGW communication is available. 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 auto-reclosure 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.

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-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 prioriting 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.

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

0 - 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.

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, 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 RLDC 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 Regional Power Committee.

(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 Special Protection System in their area, and shall inform to concerned RLDC about each change in status.

Part 2 (Measures)

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 Special Protection Systems in its area confirm and that it informed to concerned RLDC about changes in status of one of its Special Protection Systems.

2.0 DISTURBANCE MONITORING AND REPORTING

The Purpose is to ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. 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

1.1 Be provided at all substations and at locations to record all the events in accordance with CEA Grid Standard Regulation, 2010 and at locations where circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island.

1.2 Be provided at generating units above 50MVA Nameplate Rating and at Generating Plants above 300MVA Name Plate Capacity.

The following shall also be monitored at each location listed in 1.1 and 1.2:

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.
- 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.

(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.
7.3 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 data within 30 days upon request. Each LDC, Transmission Licensee and Generator Company shall provide recorded disturbance data from DRs within 30 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 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 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 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 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 mis-operations 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 Protection Sub-Committee meetings of the RPC to be held periodically. The sub-committee shall identify the lessons learnt during the events being discussed. The lessons learnt shall contain the incidence and learning details without any reference to the particular entity or location.

13.6 Each RPC 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.

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ANNEXURE-IV

3.0 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 Composite 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 Protection Sub- Committee meetings and monitor the implementation of CAP.

(4) Measures

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.

4.0 Monitoring of Special Protection System (SPS) Misoperation:

(1) Definition of SPS Misoperation:

SPS misoperations are defined as follows:

1. <u>Failure to Operate</u> – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occurs;
2. <u>Failure to Arm</u> – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;
3. <u>Unnecessary Operation</u> – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s);
4. <u>Unnecessary Arming</u> – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and
5. <u>Failure to Reset</u> – 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 Special Protection System (SPS) Misoperations
2. Analysis of all Special Protection System (SPS) Misoperations and/or
3. Mitigation of all Special Protection System (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 in a year or whenever any change in network/ modification.

(4) Measures:

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.

5.0 Need for sudden pressure released relay

[Subgroup was of the view that there is no significance of preparing standard for these relays. Hence removed from the scope of subgroup]

6.0 Need for Voltage Collapse Prediction System

[PGCIL was requested to provide material on this]

7.0 Transmission and Generation Protection System Maintenance and Testing

(1) Definitions:

1. **Protection System:** The Protection System includes Protection relays, associated communication system, Special Protection Systems, voltage and current sensing devices, DC control circuit, battery 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:

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 of the next verification of that system or component.

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.	5 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 UVLS and 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.