Agenda Notes for the 3rd Meeting of Subgroup in respect of "Preparation of reliability Standards for Protection System and Communication System"

Meeting Date: 20.01.2017
Time: 1430 Hrs

Venue: NRPC Conference hall

1. **Confirmation of minutes of 2nd meeting**

The Minutes of 2nd meeting (enclosed as ANNEXURE A) of NRCE Subgroup held on 04th November, 2016 was circulated vide letter No. 3/NRCE/NPC/CEA/2016/867-873 dated 13.12.2016.No comments were received from the members.

Members may confirm the Minutes of the 2nd meeting.

2. A draft material (enclosed as ANNEXURE B) on the following items is put up for deliberation in the 3rd meeting of the Subgroup.

- Protection Misoperation Reporting and Monitoring of Corrective Action
- Reporting of SPS Misoperation
- Need for sudden pressure released relay
- Transmission and Generation Protection System Maintenance and Testing

ANNEXURE B

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 by RPCs.

(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 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 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 the later of 24 hours of information or 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 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 seven working days of first identifying a cause of the Misoperation:
   - Develop a Corrective Action Plan (CAP) 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 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 monitor implementation of CAP.

(4) Measures

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

1. It identified 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 deliberate the reported misoperation in Protection Committee meetings and maintain the updates of implementation of CAP.

4. Monitoring of Special Protection System 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 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 Operators and System Protection personnel of the Transmission Licensee and Generator Company shall analyze all SPS operations.

1.1. They shall report and review all SPS operations to RPCs/RLDCs to identify apparent Misoperations within 24 hours.

1.2. They 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 System Operators.

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 Owner or Generator Owner 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 Transmission Licensee and Generator Company shall perform the following.

2.1.1 The Generator Company shall adjust generation to a reliable operating level, or

2.1.2. Transmission Licensee shall adjust the System Operating Limit (SOL) and operate the facilities within established limits.

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) Measures:

1. System Operators 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 taken that adjusted generation or SOLs and operated facilities within established limits.

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.

5. Sudden Pressure Relaying Maintenance

(1) Definition of Sudden Pressure Relaying

A system that trips an interrupting device(s) to isolate the equipment it is monitoring and includes the following Components:

- Fault pressure relay – a mechanical relay or device that detects rapid changes in gas pressure, oil pressure, or oil flow that are indicative of Faults within liquid filled, wire-wound equipment.
- Control circuitry associated with a fault pressure relay

(2) Objective :

Document and implement programs for the maintenance of Sudden Pressure Relaying affecting the Grid reliability so that they are kept in working order.

(3) Requirements:

1. Each Transmission Licensee, Generator Company, and Distribution Licensee shall establish a Protection System Maintenance Program (PSMP) for its Sudden Pressure Relaying.
The PSMP shall:
   1.1. Identify which maintenance method (time-based, condition-based or a combination of these maintenance methods as per CEA standards) is used to address each Sudden Pressure Relaying Component Type.

   1.2. Include the applicable monitored Component attributes applied to Sudden Pressure Relaying Component Type consistent with the maintenance intervals specified in Table where monitoring is used to extend the maintenance intervals beyond those specified for Sudden Pressure Relaying Components.

2. Each Transmission Licensee, Generator Company, and Distribution Licensee that uses condition based maintenance intervals in its PSMP shall establish and maintain its condition based intervals.

3. Each Transmission Licensee, Generator Company, and Distribution Licensee that utilizes time based maintenance program(s) shall maintain its Sudden Pressure Relaying Components that are included within the time based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals.

4. Each Transmission Licensee, Generator Company, and Distribution Licensee that utilizes condition based maintenance program(s) in accordance with Requirement 2

shall implement and follow its PSMP for its Sudden Pressure Relaying Components that are included within the condition-based program(s).

5. Each Transmission Licensee, Generator Company, and Distribution Licensee shall demonstrate efforts to correct identified Unresolved Maintenance Issues.

(4) Measures:

1. Each Transmission Licensee, Generator Company, and Distribution Licensee shall have a documented PSMP in accordance with Requirement 1. For Sudden Pressure Relaying Component Type, the documentation shall include the type of maintenance method applied (time based, condition based, or a combination of these maintenance methods).
   For Component Types that use monitoring to extend the maintenance intervals, the responsible entity(s) shall have evidence for Sudden Pressure Relaying Component Type (such as manufacturer's specifications or engineering drawings) of the appropriate monitored Component attributes as specified in Table.

2. Each Transmission Licensee, Generator Company, and Distribution Licensee that uses condition based maintenance intervals shall have evidence that its current condition based maintenance program(s) is in accordance with Requirement 2, which may include, but is not limited to, Component lists, dated maintenance records, and dated analysis records and results.

3. Each Transmission Licensee, Generator Company, and Distribution Licensee that utilizes time based maintenance program(s) shall have evidence that it has maintained its Sudden Pressure Relaying Components included within its time-based program in accordance with Requirement 3. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

4. Each Transmission Licensee, Generator Company, and Distribution Licensee that utilizes condition based maintenance intervals in accordance with Requirement 2 shall have evidence that it has implemented the PSMP for the Sudden Pressure Relaying Components included in its condition-based program in accordance with Requirement 4. The evidence may include, but is not limited to, dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, or dated work orders.

5. Each Transmission Licensee, Generator Company, and Distribution Licensee shall have evidence that it has undertaken efforts to correct identified Unresolved Maintenance Issues in accordance with Requirement 5. The evidence may include, but is not limited to, work orders, replacement Component orders, invoices, project schedules with completed milestones, return material authorizations (RMAs) or purchase orders.

Maintenance Activities and Intervals for Sudden Pressure Relaying		
Component Attributes Maximum	**Maintenance**	**Interval Maintenance Activities**
Any fault pressure relay.	6 Calendar Years	Verify the pressure or flow-sensing mechanism is operable.
Electromechanical lockout devices, which are directly in a trip path from the fault pressure, relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry).	6 Calendar Years	Verify electrical operation of electromechanical lockout devices.
Unmonitored control circuitry associated with Sudden Pressure Relaying.	12 Calendar Years	Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices.
Control circuitry associated with Sudden Pressure Relaying whose integrity is monitored and alarmed	No periodic maintenance specified	None.

7.0 Transmission and Generation Protection System Maintenance and Testing

(1) Objective:

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

(2) Requirements:

1. Each Transmission Licensee and any Distribution Licensee that owns a transmission Protection System and each Generator Company that owns a generation or generator interconnection Facility Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the Grid reliability. The program shall include:
   1.1. 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 any Distribution Licensee that owns a transmission Protection System and each Generator Company that owns a generation or 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 on request. The documentation of the program implementation shall include:
   2.1. Evidence Protection System devices were maintained and tested within the defined intervals.
   2.2. Date each Protection System device was last tested/maintained.

(3) Measures:

1. Each Transmission Licensee and any Distribution Licensee that owns a transmission Protection System and each Generator Company that owns a generation or 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 any Distribution Licensee that owns a transmission Protection System and each Generator Company that owns a generation or 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.