NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability Standard PRC-012-2 Remedial Action Schemes Question & Answer Document

Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)

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RELIABILITY | ACCOUNTABILITY




Table of Contents

Question & Answer for PRC-012-2

The Project 2010-05.3 Phase 3 of Special Protection Systems: Remedial Action Schemes (RAS) standard drafting team (SDT) developed this Question & Answer document to explain the key concepts incorporated into Reliability Standard PRC-012-2.

1. Why was the Reliability Coordinator chosen to perform the Remedial Action Scheme (RAS) review?

NERC Reliability Standards require accountability; consequently, they must be applicable to specific users, owners, and operators of the Bulk-Power System. The NERC white paper suggested Planning Coordinators (PCs) and Reliability Coordinators (RCs) for RAS-review responsibility. The SDT considered the suggestion and ultimately chose the Reliability Coordinator because of the RC has the widest possible view of the System of any operating or planning entity. Some Regions have as many as 30 PCs for one RC while other Regions or other System footprints have a single PC and RC for the same area. Overall, there are 16 RCs and approximately 80 PCs in North America. The large RC geographic oversight will minimize fragmentation of the regional reviews currently administered by the Regions and promote continuity.

The RC is the best-suited functional entity to perform the Remedial Action Scheme (RAS) review because the RC has the widest-area reliability perspective of all functional entities and an awareness of reliability issues in neighboring RC Areas. This wide-area purview provides continuity in the review process and better facilitates the evaluation of interactions among separate RAS, as well as interactions among RAS and other protection and control systems. The selection of the RC also minimizes the possibility of a conflict of interest that could exist because of business relationships among the RAS-entity, PC, Transmission Planner (TP), or other entities that are likely to be involved in the planning or implementation of a RAS. The RC is also less likely to be a stakeholder in any given RAS and can therefore maintain objective independence.

The RC may request aid in RAS reviews from other parties such as the Planning Coordinator(s) or regional technical groups; however, the RC retains responsibility for compliance with the requirement.

2. Why is the Planning Coordinator not required to perform an annual evaluation of RAS performance?

TOP-005-1 Requirement R3 requires Balancing Authorities (BA) and Transmission Owners (TO) to perform operational reliability assessments (e.g., real time contingency analysis (RTCA), day-ahead, seasonal) that include data describing new or degraded RAS. In addition, IRO-005-1 Requirement R12 requires RCs to share any pertinent data, such as data from RAS, with potentially affected BAs and TOs. Operating horizon assessments that include RAS are already required by other standards, so an additional requirement duplicating that effort is not necessary.

TPL-001-4 Requirement R2 also requires TPs and PCs to perform annual planning assessments of the near-term transmission planning horizon. Requirement R2 Part 2.7.1 acknowledges that new, modified, or removed RAS may be part of a corrective action plan (CAP) used to fulfill Table 1

performance requirements. Short-term (annual) planning horizon assessments are already required by the TPL-001-4 standard, including RAS, so an additional requirement duplicating that effort is not necessary.

3. Why is the five-year evaluation assigned to the Transmission Planner rather than the Reliability Coordinator?

Requirement R4 states that an evaluation of each RAS must be done at least every 60 calendar months to verify the continued effectiveness and coordination of the RAS, its inadvertent operation performance, and the performance for a single component failure. The items that must be addressed in the evaluations include: 1) RAS mitigation of the System condition(s) or event(s) for which it was designed; 2) RAS avoidance of adverse interactions with other RAS and with protection and control systems; 3) the impact of inadvertent operation; and 4) the impact of a single component failure. The evaluation of these items involves modeling and studying the interconnected transmission system, which is very similar to the planning analyses performed by the TPs. The RC is more focused on actual System conditions, not necessarily on the conditions for which a RAS was designed. The required evaluation is a detailed planning analysis and thus the TP is better suited than the RC to perform the evaluation.

4. Why do RAS need to be reviewed and approved by a group other than the RAS-owner?

RAS are unique and customized assemblages of protection and control equipment. As such, they have a potential to introduce reliability risks to the Bulk Electric System (BES) if not carefully planned, designed, and installed. A RAS may be installed to address a reliability issue or to achieve an economic or operational advantage, and could introduce reliability risks that may not be apparent to RAS-owners. An independent review and approval is an objective and effective means of identifying risks and recommending RAS modifications when necessary.

5. What is required for RAS "single component failure" and why is it required?

The existing PRC-012-1 Requirement 1 R1.3 states "Requirements to demonstrate that the RAS shall be designed so that a single RAS component failure, when the RAS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0." If a RAS is installed to satisfy the performance requirements of a NERC Reliability Standard, it is necessary that its operation, under the conditions and events for which it is designed to operate, be ensured in the operational realm as well as in the planning realm. Requirement R4, Part 4.4 and Attachment 1 of PRC-012-2 reaffirms this objective by stating: "a single component failure in the RAS, when the RAS is intended to operate, does not prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS was designed."

Acceptable methods for achieving this BES performance objective include the following:

- Providing redundancy of RAS components listed below:
    - Protective or auxiliary relays used by the RAS

- Communications systems necessary for correct operation of the RAS
- Sensing devices used to measure electrical quantities used by the RAS
- Station dc supply associated with RAS functions
- Control circuitry associated with RAS functions through the trip coil(s) of the circuit breakers or other interrupting devices
- Computers or programmable logic devices used to analyze information and provide RAS operational output

- Arming more load or generation than necessary such that failure of the RAS to drop a portion of load or generation would not be an issue if tripping the total armed amount of load or generation does not cause other adverse impacts to reliability.
- Using alternative automatic actions to back up failures of single RAS components.
- Manual backup operations, using planned System adjustments such as transmission configuration changes and re-dispatch of generation if such adjustments are executable within the time duration applicable to the facility ratings.

When a component failure occurs, the resulting BES performance will depend on what RAS component failed and how critical it is to the functions of the RAS. This risk can only be evaluated on an individual basis through the review process.

6. What is required for RAS inadvertent operation?

The possibility of inadvertent operation of a RAS during System events and conditions that are not intended to activate its operation must be considered. The existing PRC-012-0 Requirement 1, R1.4 states that the inadvertent operation of a RAS shall meet the same performance requirement (TPL-001-0, TPL-002-0, and TPL-003-0) as that required of the contingency for which it was designed and not exceed TPL-003-0. The drafting team clarified that the inadvertent operation to be considered would only be caused by the malfunction of a single RAS component. It is therefore possible to design security against inadvertent operation into the RAS logic and hardware such that a malfunction of any one RAS component would be unable to cause a RAS inadvertent operation, or might limit inadvertent operation of a RAS in part.

The intent of Requirement R4, Part 4.3 is to require a RAS to be designed so that its whole or partial inadvertent operation due to a single component malfunction does not prevent the System from meeting the performance requirements for the same contingency for which the RAS was designed. If the RAS was installed for an extreme event in TPL-001-4 or for System conditions not defined in TPL-001-4, inadvertent operation must not prevent the System from meeting the performance requirements specified in Requirement R4, Parts 4.3.1 – 4.3.5, which are the performance requirements common to all planning events P0–P7.

7. What is meant by RAS adverse interaction or coordination with other RAS and protection and control systems?

RAS are complex schemes that typically take actions to trip load or generation or reconfigure the System. Many RAS depend on sensing specific system configurations to determine whether they need to arm or take action. Though unusual, overlapping actions among RAS would have the potential to result in Cascading unless they were coordinated. Similarly, RAS operation can change System configuration and available fault duty, which can affect coordination with distance relay overcurrent ("fault detector") supervision and ground overcurrent protection. A third coordination example is RAS operational timing that must coordinate with automatic reclosing on a faulted line. Many RAS are intended to mitigate post-Contingency overloads. A short coordinating delay up to a few seconds is required to avoid initiating action until a System Fault can be detected and cleared by Protection System action. A delay of several minutes may be acceptable as long as it is compatible with the thermal characteristics of the overloaded equipment.

8. Why are RAS classifications not recognized in the standard?

RAS classification was suggested in the SPCS-SAMS report as a means to differentiate the reliability risks between planning and extreme RAS; however, the standard drafting team concluded the classification is unnecessary. The distinction between planning and extreme RAS is captured in Requirement R4, Part 4.4 and Attachment 1, item III.4 of PRC-012-2 that relates to single component failure; consequently, there is no need to have a formal classification for this purpose.

The standard drafting team concluded the SPCS-SAMS distinction between significant and limited RAS was unnecessary for the purpose of maintaining continuity with PRC-012-1 R1.3 which does not recognize such a distinction, and problematic due to the difficulty of drawing a universally satisfactory delineation in generally worded classification criteria.

Some Regions classify RAS to prescribe RAS design and review requirements specific to the Region. Avoiding RAS classifications in the proposed standard makes it possible to retain Regional Entity classifications and associated criteria without overlap and confusion.

9. What constitutes functional modification of a RAS?

Any change in RAS logic, relay settings, control settings, or any other modification that affects overall RAS functionality, timing, or redundancy level are changes to functionality documented in the original submission for review. RAS modifications identified by a CAP developed pursuant to Requirement R6—beyond the substitution of components that preserve the original functionality—are functional changes.

RAS retirement or removal is a form of RAS functional modification. A RAS-entity must submit the RAS data specified in the "RAS Retirement" section of Attachment 1.

The following are examples of RAS functional changes:

1. Replacement of a RAS field device if the replacement requires changes in the physical design, settings, or device custom logic.

2. Changes to the telecommunication infrastructure or communication facility, such as the replacement of a T1 multiplexor within a RAS component station. Such changes could affect the throughput timing of a RAS.
3. The addition or removal of mitigation actions within a RAS component.
4. The addition or removal of contingencies or System conditions for which a RAS was designed to operate.
5. Changes to the RAS design to account for station bus configuration changes.

The following examples are not considered RAS functional changes:

1. The replacement of a failed RAS component with an identical component.
2. A firmware upgrade of a RAS component if the change does not require changes in the RAS implementation settings or custom logic.

10. Why is the RAS-entity identified in the standard and what are its responsibilities?

The purpose of the RAS-entity is to be the single information conduit with the reviewing RC for all RAS-owners for each RAS. The RAS-entity needs to coordinate all review materials and any presentations. If all RAS equipment has a single owner, then the RAS-entity is the RAS-owner, and that owner speaks for itself.

A RAS can have more than one owner. The RAS-entity is always one of the RAS-owners and is designated by all RAS-owners. Historically, the owner of the RAS controller (most commonly a Transmission Owner) is the RAS-entity.

RAS-owners who are not the RAS-entity still have responsibilities as assigned in other NERC standards, such as equipment maintenance in PRC-005. In addition, when RAS modifications are needed; e.g., per Requirement R6 or Attachment 1, each RAS-owner must participate in developing a CAP and accept the specific responsibilities assigned to them in the CAP or otherwise as described in the revised Attachment 1.

Attachment A – Project Roster

Project 2010-05.3 – Remedial Action Schemes		
	Participant	**Entity**
Chair	Gene Henneberg	NV Energy / Berkshire Hathaway Energy
Vice Chair	Bobby Jones	Southern Company
Member	Amos Ang	Southern California Edison
Member	Alan Engelmann	ComEd / Exelon
Member	Davis Erwin	Pacific Gas and Electric
Member	Sharma Kolluri	Entergy
Member	Charles-Eric Langlois	Hydro-Quebec TransEnergie
Member	Robert J. O'Keefe	American Electric Power
Member	Hari Singh	Xcel Energy
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